IN THE MATTER OF

FORTISBC INC.

MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 THROUGH 2018

DECISION

September 15, 2014

Before:

D.A. Cote, Panel Chair/Commissioner
N.E. MacMurchy, Commissioner
D.M. Morton, Commissioner

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EXECUTIVE SUMMARY

On July 5, 2013, FortisBC Inc. (FBC) applied to the British Columbia Utilities Commission (Commission) for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014–2018 (Application). The Application is made pursuant to sections 44.2 and 59 through 61 of the *Utilities Commission Act* (UCA). FBC seeks approval of, among other things:

- PBR mechanisms and the rate stabilization mechanism for setting rates for the years 2014–2018.
- Permanent rates for all customers effective January 1, 2014 resulting in an increase of 3.3 percent over 2013 and the flow-through of any rate increase or decrease resulting from the Generic Cost of Capital (Stage 2) proceeding.
- Deferral accounts additions, changes and discontinuance as well as proposed changes in financing costs.
- Accounting policies including the allocation of executive costs, the capitalized overhead rate and direct overhead charging methodology.
- Demand-Side Management (DSM) related to 2014–2018 expenditures and amortization changes.

FBC filed this 2014–2018 PBR plan based on the following objectives:

1. To reinforce FBC's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

On July 5, 2013, FortisBC Energy Inc. (FEI) filed a similar application. Portions of each application concerned with the PBR mechanism were combined into a joint proceeding. For convenience, the joint applicants in that portion of the proceeding are referred to as Fortis.

Many of the interveners expressed concern with the FBC proposal and recommend denying the Application in favour of moving forward with additional process to resolve the issues that arose. Considering the time and money spent to conduct the proceeding and the considerable volume of evidence, the Commission Panel determines it is appropriate to move forward with the process and render a decision based on the substantial evidentiary record. The Panel considers much of the problem among the parties is based on a lack of trust, which must be addressed if a PBR regimen is to be successful.

The Decision following the Introduction section is separated into three sections:

1. PBR Design which deals with determinations related to the PBR formula components and elements of the PBR plan including the management of Service Quality Indicators (SQIs);
2. Making the PBR Work which addresses key revenue requirement issues including Base Operating and Maintenance (O&M) and Base Capital, accounting policy proposals and a number of issues with deferral accounts; and
3. Demand-Side Management (DSM) Programs.

PBR Design

A brief summary of some of the key issues and determinations related to the PBR design components are as follows:

PBR Formula Components

(a) **PBR Term:** Fortis' proposal is for a five-year PBR term starting in 2014. Most interveners favoured a shorter term pointing to the risk associated with a five-year term. The Commission Panel, in recognition of the timing of this Decision, determines that a six-year period ending in 2019 is optimum. In the Panel's view, the changes made to certain PBR mechanisms provide the necessary checks and balances to protect ratepayer interests.

(b) **I-Factor:** The Commission Panel supports the use of CPI-BC and the BC-AWE indexes in the determination of the I-factor as recommended by Fortis. However, the Panel is not persuaded that relying on forecast data to determine the I-factor is appropriate. We find that a reliance on the previous year's actual index figures, while backward looking, has significant advantages and therefore have determined this method to be most appropriate.

(c) **X-Factor:** Considering the opposing views of two expert witnesses, Dr. Overcast on behalf of Black and Veatch (B&V) and Dr. Lowry on behalf of Pacific Economic Group (PEG), the Panel does not accept the B&V study results due to methodology shortcomings and resulting errors but places considerable weight on the PEG study considering it more rigorous. The Commission Panel determines that an X-factor of 1.03 is appropriate for FBC.

PBR Plan Components

(a) **Earnings Sharing Mechanism:** The Commission Panel determines that an Earnings Sharing Mechanism, where gains and losses are shared equally by the Company and the ratepayer, balances the interests of the customer and the utility.

(b) **Efficiency Carry-over Mechanism:** Fortis' proposes an efficiency carry-over mechanism (ECM) to allow the utility to benefit from savings following the PBR period resulting from measures taken and costs incurred during PBR. The interveners oppose this proposal considering it one sided and favouring the utility. The Commission Panel denies the Fortis ECM request but approves a methodology to review specific requests to carry over efficiency related benefits.

(c) **Service Quality:** Considering the evidence, the Commission Panel determines there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. It further determines a list of SQIs and sets performance benchmarks for each. The Panel acknowledges the need for an acceptable performance range for each SQI and directs the Fortis Companies, in consultation with the stakeholders, to develop these ranges.

(d) **Capital Expenditures:** Fortis has proposed an approach to capital which excludes CPCNs from the PBR plan. Interveners have raised concerns with respect to inclusion of capital pointing out that even with CPCN capital excluded, the potential to underspend exists. The Commission Panel finds the Fortis proposed CPCN criteria inappropriate for determining what capital is excluded from the PBR formula and invites further submission from parties on this issue. On a temporary basis, the Panel approves the current CPCN exclusion criteria and sets a process to further examine issues related to dollar thresholds and management of capital within the PBR.

(e) **Mid-Term and Annual Review Process:** The Commission Panel finds that an extensive Annual Review process is necessary to build trust among the stakeholders and ensure the PBR plan functions as intended. The Panel sets out a list of items, which it directs the parties to address within the Annual Review. Given this more comprehensive approach to Annual Reviews, there is no need for the proposed Mid-Term Review and it is therefore denied.

Making the PBR Work

A brief summary of some of the key issues and determinations related to FBC's Non PBR components are as follows:

Determining Base O&M and Capital

(a) **Base O&M:** The methodology for determining Base O&M proposed by FBC is to use the 2013 Approved O&M as a starting point and make adjustments to arrive at the PBR Opening Base O&M figure. Interveners expressed concern with both the methodology and the proposed adjustments. The Commission Panel determines that 2013 Approved O&M is an appropriate starting point and determines that further adjustments to the PBR Opening O&M Base are required resulting in a minor overall reduction to FBC's proposed base.

(b) **Base Capital:** Given that there is to be a more fulsome review of issues related to dollar thresholds and the management of capital within the PBR, the Commission Panel approves FBC's approach to formula capital and approves FBC's PBR Opening Capital Base as applied for, subject to further adjustment as directed elsewhere in this Decision.

Accounting Policies

The Commission Panel approves a number of proposed accounting changes, including discontinuance of the US GAAP to Canadian GAAP reconciliation, changes to the handling of pension and OPEB funding differences and application of the Massachusetts Formula for executive costs. The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014 as well as to commence expensing its annual software upgrade costs consistent with the direction provided to FEI in its current RRA Decision.

Deferral Accounts

(a) **Deferral Account Financing:** FBC requests revisiting the Commission's 2012–2013 RRA Decision relative to the handling of financing costs. The Commission Panel considers the matter to be of sufficient importance to warrant a more fulsome review of deferral accounts and has recommended the Commission initiate such a review in the near future. The Panel considers it appropriate to maintain FBC's deferral account financing as it is currently approved pending such a review.

(b) **RSDM Deferral Account:** The Commission Panel denies FBC's proposal to establish the Rate Stabilization Deferral Mechanism (RSDM) deferral account combining the impact of the Waneta Capacity Purchase Agreement and other PBR rate impacts.

(c) **Deferral Accounts for Flow-Through Items:** The Panel denies the establishment of the Insurance Expense Variance deferral account, Tax Variance deferral account, Property Tax Variance deferral account and Interest Expense Variance deferral account. FBC is directed to flow-through variances between forecast and actual expenses in these accounts through the annual true-up mechanism.

(d) **Other Deferral Accounts:** The Panel approves the addition of, changes to and discontinuance of deferral accounts as proposed by FBC with the exception of deferral accounts mentioned above. The Panel applies, where appropriate, financing costs and amortization periods as outlined in the 2012–2013 RRA Decision.

Demand-Side Management

FBC withdrew its request for the 2015–2018 Demand-Side Management (DSM) expenditures as a result of amendments to the DSM Regulations, retaining its request for approval of $3.0 million for 2014. Given that the timing of this Decision will not meaningfully impact 2014 DSM expenditures, the Commission Panel approves FBC's $3.0 million DSM expenditure request for 2014. In addition, the Panel denies the FBC request to increase the DSM amortization period from 10 years to 15 years.

1.0 INTRODUCTION

1.1 Background

FortisBC Inc. (FBC) is a wholly owned subsidiary of FortisBC Holdings Inc. that generates, transmits and distributes electricity to approximately 163,000 direct and indirect customers including residential, commercial and industrial users. Its service territory is located in the southern interior of British Columbia.

On July 5, 2013, FBC submitted an application seeking British Columbia Utilities Commission (Commission) approval of a multi-year performance based ratemaking (PBR) plan for the years 2014 through 2018 (PBR Plan) including approval of rates for 2014 in accordance with the PBR Plan (Application).

On July 5, 2013, FortisBC Energy Inc. (FEI) filed a similar application. Portions of each application concerned with the PBR mechanism were combined into a joint proceeding. For convenience, the joint applicants in that portion of the proceeding are referred to as Fortis.

In its Application, FBC cites the following primary objectives of the PBR Plan:

- To reinforce FBC's productivity improvement culture while ensuring safety and customer service requirements continue to be met; and
- To create an efficient regulatory process for the upcoming years allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

FBC has had two previous PBR plans in the past (1996–2004 and 2007–2011). From 2005 to 2006 and from 2012 to 2013 FBC was regulated under the Cost of Service (COS) rate setting mechanism.

1.2 Application and Approvals Sought

FBC is seeking certain approvals under section 59–61 of the *Utilities Commission Act* (UCA) in order to implement a new five-year PBR Plan. The approvals sought are broken down into several areas and are described below.

1.2.1 PBR Plan and Rate Stabilization

FBC seeks:

- Approval of the PBR mechanisms set out in Section B of the Application for setting rates for the years 2014–2018;
- Approval for the rate stabilization mechanism set out in Section B7.1 of the Application.

1.2.2 General Rate Increases

- Approval of the rates that were effective January 1, 2013 to be made permanent;
- Approval of the current interim rates, effective January 1, 2014 and reflecting a 3.3 percent increase to be made permanent; and
- Approval to flow-through during 2014 the revenue requirement impact of the decrease in return on equity (ROE) used to calculate FBC's rates effective January 1, 2013.

1.2.3 Accounting Policies Changes, effective January 1, 2014

FBC seeks:

- Approval to discontinue the reconciliation of US Generally Accepted Accounting Principles (GAAP) to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application;
- Approval to discontinue the net-of-tax treatment for the pension and other post-employment benefits (OPEB) funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of the income tax expense as explained in Section D3.1 of the Application;
- Approval to allocate Executive costs between FortisBC Energy Inc. (FEI) and FBC effective January 1, 2014, by way of applying the Massachusetts Formula described in Section C 4.17 of the Application;
- Continued approval of FBC's capitalized rate of 20 percent as set out in Section D 3.7;

- Continued approval of FBC's direct overhead charging methodology as set out in Section D3.8 of the Application.

1.2.4 Deferral Accounts

FBC seeks approval of the following:

- Rate based treatment and financing of deferral accounts, as set out in Section D3.2 of the Application;
- Financing costs for 2013 at FBC's Weighted Average Cost of Capital (WACC) for the six deferral accounts approved by Order G-23-13 as set out in Sections D4.4 of the Application; and
- The discontinuance, modification and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, as set out in Section D4 and Appendix F4 of the Application.

1.2.5 Demand-Side Management (DSM) Expenditures

Pursuant to section 44.2(3) of the UCA and as amended by FBC's letter dated July 16, 2014, FBC seeks Commission approval for:

- DSM expenditures in the amount of $3.0 million for 2014;
- Approval to change the amortization period of existing and future DSM expenditures from 10 years to 15 years, effective January 1, 2014; and
- Approval to discontinue semi-annual reporting on its DSM Program and to submit annual reports as of December 31, in each year, effective January 1, 2014.

1.3 Legislative Framework

FBC is seeking approval of a PBR Plan for the 2014–2018 time frame including appropriate rate increases pursuant to sections 59 to 61 of the UCA. In summary, these sections of the UCA require any Commission Panel to have due regard for setting rates that are not unjust or unreasonable in respect to services provided by the applicant. Subsection 59(5) states that a rate is 'unjust' or 'unreasonable' if it is:

a. more than a fair and reasonable charge for service of the nature and quality provided by the utility,

b. insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

c. Unjust and unreasonable for any other reason.

FBC is also seeking approval of proposed DSM capital expenditures for the duration of the PBR Plan (2014–2018) pursuant to subsection 44.2(3) of the UCA.

Approval of the DSM expenditures for 2014 is sought pursuant to Subsection 44.2(3), which states:

> After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6) must
>
> a. Accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public interest, or
> b. Reject the schedule.

Subsection 44.2(4) allows the Commission to accept or reject a part of a schedule.

Subsection 44.2(5) indicates the factors which the Commission is required to consider in the review of an expenditure schedule filed by a public utility (other than the British Columbia Hydro and Power Authority). It states:

> In considering whether to accept an expenditure schedule … the Commission must consider:
>
> (a) The applicable of British Columbia's energy objectives,
>
> (b) The most recent long-term resource plan filed by the public utility under section 44.1, if any,
>
> (c) The extent to which the [expenditure] schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act,*
>
> (d) If the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any,
>
> [Demand-Side Measures Regulation BC Reg. 326/2008 as amended by BC Reg. 228/2011 and BC Reg. 141/2014 is applicable]

(e) The interests of persons in British Columbia who receive or may receive service from the public utility.

The Demand-Side Measures Regulation (BC Reg. 326/2008) (DSM Regulation) was amended by BC Reg. 228/2011 and BC Reg. 141/2014. The DSM Regulation applies to demand-side measures proposed in long-term resource plans filed under section 44.1 of the UCA as well as those proposed under section 44.2 of the UCA.

Part of the DSM Regulation defines the class composed of all demand-side measures proposed by a public utility in an expenditure schedule submitted under section 44.2 of the UCA as an expenditure portfolio.

Section 3 of the DSM Regulation sets out all the criteria that must be met for a utility's plan portfolio to be deemed 'adequate' for the purposes of subsection 44.1(8)(c) of the UCA. To meet these criteria, the plan portfolio must include:

(a) a demand-side measure intended specifically

(i) to assist residents of low-income households to reduce their energy consumption, or

(ii) to reduce energy consumption in housing owned and operated by

A. a housing provider incorporated under the *Society Act* or the *Cooperative Association Act*, or

B. a band within the meaning of the *Indian Act* (Canada),

if the benefits of the reduction primarily accrue to

C. the low-income households occupying the housing,

D. a housing provider referred to in clause (A), or

E. a band referred to in clause (B) if the households in the band's housing are primarily low-income households.

(b) a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) an education program for students enrolled in schools within the public utility's service area;

(d) an education program for students enrolled in post-secondary institutions in the utility's service area.

Section 4 of the Demand-Side Measures Regulation provides for the calculation of the effectiveness of demand-side measures. It also prescribes how the cost-effectiveness of a demand-side measure is to be determined for demand-side measures proposed in an expenditure portfolio. The prescribed calculation is called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost (TRC) test.

Clean Energy Act

The Commission is required to consider British Columbia's energy objectives as laid out under the *Clean Energy Act* (CEA) in reviewing any proposed expenditure schedule. The objectives are laid out in section 2 of the CEA and relate in large measure to the use of clean energy or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions.

1.4 Regulatory Process

FBC filed its Application on July 5, 2013. By Order G-109-13 dated July 17, 2013, a Preliminary Regulatory Timetable, Procedural Conference and Notice of Workshop were issued. The Procedural Conference date was originally set for October 11, 2013.

There were eleven Registered Interveners, although not all fully participated in the regulatory hearing process. The Registered Interveners were:

- BC Ministry of Energy and Mines (MEM);
- Irrigation Ratepayers Group (IRG);
- British Columbia Pensioners' and Seniors' Organization (BCPSO);
- Canadian Office and Professional Employees Union Local 378 (COPE);
- British Columbia Municipal Electrical Utilities (BCMEU);
- Commercial Energy consumers of British Columbia (CEC);

- Norman Gabana;
- BC Sustainable energy Association and the Sierra Club of British Columbia (BCSEA);
- British Columbia Hydro and Power Authority (BC Hydro);
- Industrial Consumers Group (ICG);
- Henry Stanski.

There were five expert witnesses who provided evidence and actively participated in the regulatory process. Expert Witnesses and their respective parties were as follows:

- Dr. H. Edwin Overcast on behalf of Black & Veatch (FEI and FBC);
- Ms. Barbara R. Alexander (COPE);
- Mr. Russ Bell (BCPSO);
- Dr. Mark Lowry on behalf of Pacific Economic Group (CEC);
- Mr. Tony Pullman on behalf of ICG.

On June 10, 2013, FEI filed an application also seeking to implement a PBR Plan of five years duration (2014–2018). Details of the ensuing process and proceeding are summarized in Appendix A to this Decision.

1.5 Approach to this Decision

This Decision is separated into 4 Sections.

Section 1 provides background as well as an outline of the legislative framework and regulatory process for this proceeding. This section will continue with a discussion of some of the issues which arose within the context of the proceeding and provide some guidance to the determinations which follow.

Section 2 considers the PBR Methodology. This includes a discussion and determinations on key design issues such as the PBR Formula components, the PBR Plan components and the management of Service Quality.

Section 3 covers how the PBR will work. It includes key issues like setting the Base for Operating and Maintenance (O&M) and Capital, Accounting Policy Issues and the Use of Deferral Accounts.

Finally, Section 4 considers issues related to DSM.

1.6 Issues Arising

Two contextual issues arose in this Proceeding, which need to be addressed as they serve to provide guidance to determinations made in this Decision. These issues are:

- Why Performance Based Regulation; and
- A Fair Rate of Return Under PBR.

1.6.1 Why Performance Based Regulation

The fact that FBC has filed an Application for PBR is not a surprise to the Commission given that FBC has operated under PBR for much of the last two decades and has been open about its intentions. What is surprising is the position taken by interveners with respect to PBR. After what appeared to be support for a PBR, a number of interveners are calling for a rejection of the PBR Plan as proposed by FortisBC Energy Inc. and FortisBC Inc. (Fortis) and recommend moving forward with further process to resolve the matter. The issue the Commission Panel must consider is whether the objections to PBR relate to performance based ratemaking itself or whether the concerns raised are founded on a desire to circumvent the established process and embark on an undefined process more to the Interveners' liking. In considering this issue, the Panel is mindful that an alternative negotiated settlement process was considered in the Reasons for Decision attached to Order G-150-13 issued on September 12, 2013. In these Reasons, the Panel stated "[f]or the PBR mechanism review, the Panel finds that that the oral hearing which provides an opportunity to cross examine expert witnesses is the most appropriate means to obtain a complete evidentiary record necessary to assess these complex and challenging methodologies" (Exhibit A-13, Reasons for Decision, p. 4). Having completed the regulatory process which included an oral hearing, the Panel will consider the fullness of the evidence in reaching its determination as to whether a PBR is appropriate and whether there is a need for additional process.

1.6.1.1 A Case for PBR

After two years of COS regulation, FBC has opted to file a multi-year PBR. FBC has filed this 2014–2018 PBR Plan based on the following primary objectives:

1. To reinforce FBC's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing cost for customers.

FBC states that its proposed PBR Plan builds on the successful components of its most recent PBR Plan, which ran from 2007 through 2011. The current Plan, like the earlier PBR, establishes a formula-driven approach to calculating O&M and also introduces a formula-driven approach to calculating capital expenditures. Fortis considers these to be areas where it has the greatest control. FBC asserts that the proposed formula will result in lower spending targets in both of these areas when compared to the five-year O&M and capital forecast prepared by the Company. This is because it is incented to invest in new efficiencies to meet targets driven by the formula. In those years where the Company achieves efficiencies greater than those driven by the formula, the financial benefits are shared with customers, as are any shortfalls. The proposed PBR Plan utilizes flow-through accounts and annual forecasts to ensure that customers pay only the actual cost in those areas where FBC has limited or no control thereby protecting customers and the Company from the impact of forecast variances. The PBR Plan also includes off-ramp mechanisms to deal with cases where financial results fall outside a band of reasonableness or where there is serious, sustained and unjustified service quality degradation.

B&V provides a study of PBR methodologies and concludes there is no one right PBR model and the adopted FBC framework should be in keeping with the Company's circumstances. FBC's position is that the proposed PBR Plan, as a model, will encourage it to seek efficiencies over the term of the plan with both customers and the Company benefiting while ensuring that safe and reliable service is maintained. B&V endorses the plan as being reasonable in the circumstances but believes the "stretch" productivity factor proposed by Fortis is more aggressive than is warranted. (Exhibit B-1, pp. 1–3)

FBC states that a priority is to improve productivity and create efficiencies to allow for rates to be more effectively managed, yet maintain a customer service focus. To this end, through 2012 and 2013 "employees were asked to consider embedded practices and rethink work while maintaining appropriate service levels" (Exhibit B-1, p. 12). FBC reports that this has resulted in efficiencies being realized from streamlined processes, leveraging technology and the optimization of integration opportunities. FBC states that efficiency review activities and finding productivity gains will continue to be a focus with an emphasis on managing costs. FBC further states:

> "In providing value for FBC's customers while delivering safe and reliable service at the most reasonable cost, a productivity focus is a requirement and is ingrained into the Company. The implementation of the PBR Plan proposed in this Application will result in a continuation of this focus through the PBR Period, and in an equal sharing with customers of any resulting incremental savings above the productivity factor built into customer rates." (Exhibit B-1, p. 14)

Intervener Submissions

In concluding its Opening Statement in the Oral Hearing, CEC states: "CEC is in support of PBR. This is not an issue. It simply does not see this proposal of the company at this time as aligned with customer interests and we will deal with how that may be improved in our final submissions and through this proceeding" (T2:188). CEC, in its Final Argument "recommends that the Commission deny the Utilities application for their proposed PBR process and direct the parties to commence discussion with respect to alternatives that may more suitably align customer interest and the Utilities interest." A summary of CEC's position includes the following concerns:

- The PBR formulas proposed by Fortis are overly generous and are likely to result in the utilities enjoying windfall gains.

- The PBR has incentives which could lead to losses or inappropriate gains for the customer. The build-up of expenses before entering PBR and the deferral of expenditures late in a PBR period serve as examples of such perverse incentives.
- The Fortis proposal includes numerous examples of misalignment with customer interests and has not assessed alternatives due to its failure to consult with customer groups. CEC continues by noting 178 examples of misalignment of ratepayer interest to shareholder interest it has identified and therefore, approval of such a PBR proposal does not balance interests.
- Fortis has not made a sufficient business case for regulatory efficiency.

(CEC PBR Final Argument, p. 7)

CEC continues its submissions for a total of 219 pages outlining its concerns and sharing its view as to how the various PBR components can be better aligned with customer interests.

ICG reaches a similar conclusion with respect to FBC in that the PBR proposal is not aligned with customer interests and substantial changes are necessary. However, even with these changes, ICG does not support a PBR Plan at this time. (ICG Final Argument, p. 1)

IRG acknowledges the economic basis for PBR generally but asserts that FBC has not adequately explained why a change to PBR is required. IRG asserts that FBC has not established that a PBR will result in material expansion of incremental efficiency savings or that regulatory efficiency will result if PBR is implemented. (IRG Final Argument, pp. 1, 10)

COPE, in its Final Argument provided comments on some of the strengths and weaknesses of PBRs but took no position on the Application as a whole. COPE did provide detailed submissions on Service Quality Indicators (SQIs).

BCPSO took no position on whether to deny the Application but outlined alternative positions to those of Fortis with respect to customer alignment and balance in its Final Argument.

BCMEU, in its Final Argument supports the arguments of CEC and the need for a PBR with a good balance of risk and reward.

The matter of whether to go forward with a PBR was addressed again within the context of the Oral Argument phase of the proceeding held on July, 14, 2014. The Interveners were consistent in their opposition of the PBR as proposed by Fortis. However, CEC did submit that an "improved and ongoing PBR could serve to mitigate customer concerns" (T8:1415). It continued by recommending that a BCUC supervised process be initiated immediately to develop a PBR process more aligned with customer interests.

Fortis Reply

In the view of Fortis, interveners like CEC, BCPSO and ICG pay lip service to the concept of a PBR while objecting to its fundamental elements. Fortis holds that the case in favour of PBR is compelling. It states that interveners representing customers consider COS to be the gold standard pointing to the detailed review of costs and typical rebasing every two years as the reason. This is in comparison to PBR where there are less detailed reviews of utility costs over the PBR period and a longer period (in this case five years) between rebasing. In Fortis' view, the reason why PBR remains an accepted ratemaking model is that these two features are fundamental to the values of productivity and efficiency that the PBR delivers to utility customers. Fortis argues that:

- Extending the time before rebasing incents the utility to search for incremental efficiencies.
- The more streamlined regulatory process related to PBR increases the likelihood of achieving direct and indirect savings.
- An appropriate level of transparency can be achieved with a less intensive regulatory process in PBR.

Fortis considers much of the concern raised by interveners to be misconceptions. Some examples of these follow.

Fortis argues that some of the interveners consider PBR to be misaligned with customer interests by providing windfalls to the utility and harming customers by creating inappropriate incentives. It considers these views to be misconceived and to lack recognition of short and long-term customer benefits as commented on by both CEC's expert witness, Dr. Lowry, and Fortis' expert witness, Dr. Overcast. Fortis further states that the achievement of a higher than approved ROE is a benefit because this only occurs when benefits have flowed to both parties. By comparison, under COS, 100 percent of the benefit flows to the Company and the customer obtains benefits only after rebasing.

In response to concerns raised by Interveners that the PBR Plan does not distinguish between efficiency gains and cost cutting, Fortis further states that cost cutting is efficient and beneficial. Fortis argues that the distinction is artificial as by definition efficiency occurs when the earned return equals or exceeds the allowed return under revenue cap when a positive stretch factor exists. In addition, Fortis states that the opposition of interveners to mere cost cutting seems to be based on a misconception that under-expenditures are a product of gamesmanship related to perverse incentives and are made at the expense of service quality and asset integrity. The Company points out that these types of arguments ignore the presumption of good faith and the existence of a regulator.

Fortis asserts that PBR will bring regulatory efficiency, pointing out that revenue requirements applications are 10 to 30 times more costly than the Annual Review process under PBR. In addition, it is intuitive that there is a direct benefit related to having utility employees focus on managing the business rather than the regulatory process. (Fortis PBR Final Argument, pp. 1–16)

Fortis is unequivocal in stating that there is not a need for further process. Fortis is of the view that there are fundamental differences among the parties and “that is precisely the time when the Commission needs to come in and make a decision” (T8:1474).

Commission Determination

In the words of COPE, “between the interveners in this process, there were some significant commonalities in their evaluation of the PBR, not the least of which was the universal opposition to the particular set of applications…” (T8:1456). The Commission Panel does not disagree and considers the proposals as put forward by the Fortis Companies to favour Fortis. The discussion of evidence put forward in this proceeding, which follows in Section 2.0, bears this out.

The submissions of the parties seem to suggest that the concerns of the parties are not with a PBR itself but with the specifics of the Applications put forward by the Companies. CEC made this clear in its opening statement at the Oral Hearing, noting that it would provide recommendations on how the proposed Application could be improved during the Oral Hearing and in its Final Arguments. Its lengthy Final Argument listed its many concerns with recommendations as to how they should be addressed. It thus appears that CEC's concern is not with whether a PBR should be established, but with how the PBR elements should be more balanced in the interest of all stakeholders. Of the Interveners, only ICG and IRG are firm in not wanting to move forward albeit for different reasons. Of the remaining parties who commented, all seemed to favour some form of cost of service arrangement for the short term and a process to bring the parties together to discuss some form of PBR alternative for the future.

The Commission Panel notes that considerable time and money has been spent to conduct this PBR proceeding. Over the past year, the parties and the Commission have read through the Applications, volumes of IRs and considered the evidence, both oral and written, from a number of expert witnesses. The evidentiary record on which to base a decision is substantial. Add to this the level of differences among the parties with regard to various aspects of the PBR proposal and it is questionable whether any value will result from further process. **Therefore, the Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.**

In moving forward with this PBR Decision the Panel has a number of concerns.

The Commission Panel is not looking at this Application from a short–term viewpoint. We see an opportunity to make significant change over the long term with the way regulation is conducted in this jurisdiction and the way in which revenue requirements are determined. What form this may take is at this point undecided. Standing in the way of this is the lack of trust among the parties. If moving forward with this PBR is going to work, the level of trust must be addressed and increased. For this reason, the Commission Panel has included a more lengthy discussion of the Annual Review process in this Decision than perhaps many of the parties anticipate. We have made significant changes to the purpose, content and process for this important program element. This will be discussed further in Section 2.3.6.

Much has been said by the parties about the improved regulatory efficiency that will result from a PBR process. Fortis seems to view PBR as a period where it will be required to provide only limited information as to its activities and savings it has achieved. This is a sticking point with interveners who are outspoken in their concerns with respect to the level of scrutiny and oversight of the activities of FEI and FBC over the PBR period. The Commission Panel acknowledges that improving regulatory efficiency is a desired outcome but due to the current levels of trust, the achievement of major regulatory savings in the first few years of PBR may not be possible or even advisable.

Looking at regulatory models more broadly, the Commission Panel accepts that there is no perfect regulatory process. The COS model has been relied upon in this jurisdiction and others with some success. The interveners may take comfort in the fact that one of its advantages is that it requires more frequent rebasing and hence there is a limit on the time before any sustainable savings directly impact customer rates. However, with COS regulation, there is little incentive to make sustainable efficiency gains and even less when an investment is required. In fact, perversely, the utility may be incented to make unsustainable savings. On the other hand, the PBR model comes with its own set of inherent problems. If the wrong base is set for O&M or capital, or inappropriate I- or X-factors are set which favour either party, it can result in additional gains for that party over a longer period of time unless an off-ramp is tripped.

Regardless of the method chosen, to be successful over the longer term, the parties need to feel that their concerns are heard and where reasonable, acted upon. To facilitate this, the Commission Panel has taken steps in this Decision to ensure there is ongoing communication between the parties, which will result in greater transparency.

1.6.1.2 A Fair Rate of Return Under PBR

Fortis has relied on a number of guiding principles in developing its PBR Plan proposal. One of these states: "The PBR Plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return" (FEI Exhibit B-1, p. 43; FBC Exhibit B-1, p. 39). Whether rates are set under COS or a PBR Plan, the Commission remains tasked with setting just and reasonable rates under sections 59 to 61 of the UCA.

> "As reflected in section 59(5), just and reasonable rates must represent:
>
> - a 'fair and reasonable charge for service of the nature and quality provided by the utility' and
> - 'a fair and reasonable compensation for the service provided by the utility'" (Fortis PBR Final Argument, p. 17).

Fortis submits that this includes the well-established right of a utility to earn a fair return and the assessment of the PBR plan needs to be on a holistic basis as rate levels are a product of the plan elements working in tandem to yield a revenue requirement. Fortis' expert witness, Dr. Overcast describes the concept of just and reasonable rates in a PBR context as follows:

> "The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level…."
> (Exhibit B-1-1, Appendix D2, p. 7)

Fortis considers Dr. Overcast's description to be reasonable and submits that for the PBR plan to meet legislative requirements, three conditions must be present:

- An appropriate base on which to apply the PBR formula;
- A plan which has been crafted with a recognition of the extent to which costs are controllable by the utility; and

- The I-X formula applicable must realistically portray inflation impacts and other productivity factors impacting the X-Factor and the I-X formula result must be reasonably achievable.

(Fortis PBR Final Argument, pp. 17–18)

Commission Determination

The Commission Panel is in agreement with Fortis that the revenues driven by the PBR formula must provide utilities the opportunity to earn a fair return. The Panel also acknowledges that changes to individual plan components "may change the overall risk/reward profile of the PBR Plan." The UCA addresses this in section 60(1)(a):

In setting a rate under this act

(a) the commission must consider all matters it considers proper and relevant affecting the rate,

(b) the commission must have due regard in the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59…

Fortis has put forward a PBR plan with numerous elements. As outlined by Dr. Overcast, each of the elements needs to be scrutinized carefully. This is to ensure they are reasonable and do not favour either the Companies or the ratepayer. Determinations resulting from this evaluation need to achieve a proper balance of risks and rewards between the Companies and the ratepayer and reflect current reality.

FEI and FBC's Applications provide forecasts for O&M and Capital for the period 2014 to 2018. The Companies compare these forecasts against outputs from their proposed PBR mechanism and show that there are similar patterns between their forecasts and the amounts generated by the proposed PBR mechanism. Fortis takes the position that this similarity of pattern or balance must be maintained with any changes that the Commission may make to the formula. The Commission Panel notes that the validity and accuracy of these forecasts has not been established. Therefore, there is no basis on which to justify this comparison between the PBR mechanism and the Fortis forecasts. While there is a need to holistically consider the effects of changes to the PBR mechanism on the Companies' ability to earn a fair return, the Panel places no weight on the Fortis assertion that Commission changes must be balanced against what the Companies have submitted. Accordingly, the Commission Panel finds there is no requirement to balance Commission adjustments to the PBR against the revenue requirement forecasts provided by Fortis.

2.0 FORTIS PBR DESIGN

2.1 Background

2.1.1 <u>Experience with PBR</u>

FBC has had experience with a formula driven PBR regime operating two previous PBR plans; one in 1996–2004 and a second in 2007–2011. FBC reports that both of its previous plans were successful and building on this it has incorporated many of the elements of previous plans. In addition, it has made adjustments to these as appropriate.

FortisBC (then West Kootenay Power) states that in 1996 it received Commission approval to replace its Cost of Service plan with a PBR. FBC describes the plan as consisting "of 'targeted' cost categories with cost drivers, base costs escalators, productivity improvement factors (PIFs) and a sharing mechanism." In addition, performance standards that were subject to periodic review were made part of the plan, which ran for three years but was extended on two occasions with some modification. The modifications included some of the incentive mechanisms in the original plan such as the introduction of a power purchase mechanism and market incentive mechanism as well as excluding capitalized overhead from the mechanism.

The 2007–2011 PBR plan was based on a negotiated settlement and was like the previous plan in many aspects. A key difference between the two plans was the exclusion of capital expenditures, which were not part of the 2007–2011 PBR plan and were approved by annual filing or by CPCN applications. Additionally, an Earnings Sharing Mechanism (ESM) was introduced and "replaced the previously-existing line-by-line review used to determine the level of any incentive sharing between the Company and its customers." Further modifications included performance indicator changes.

These were designed to improve the measurement of customer satisfaction with service quality and reliability as well as the convenience of customer interactions. (Exhibit B-1, p. 31)

2.1.2 PBR Approaches

Approaches to PBR fall into two broad categories: price caps and revenue caps. Under a price cap formula, rates are a function of two factors; the previous year's rates and a formula which is applied to those rates. Typically, the formula accounts for inflation (or an I-Factor) and an efficiency factor (referred to as the X-factor) and may also include other terms to account for such things as growth, flow-through items and exogenous events. The revenue cap approach differs from this in that it is the utilities' allowed or authorized revenue that is subject to the formula.

While both of these methods serve to create incentives to reduce costs and raise efficiency, they differ in the way they treat energy demand and incremental sales volumes. Under the price cap model the utility takes on the risk for demand variations. Therefore, they are encouraged to maximize sales volumes to the point where their marginal revenue equals their marginal costs. FBC states that this method is more appropriate for utilities with a demand trend that is stable and growing. It can be problematic in those cases where there is a continuous decline in sales per customer due to exogenous factors. This makes a price cap problematic for FEI where gas usage rates are trending down. Under a revenue cap model as is proposed in this Application, allowed revenue is decoupled from demand, which provides the utility protection against such variation in demand.

Revenue Cap plans are typically further broken down into either a "building block" approach or a "total expenditure" approach based on their rate base assessment methodology and the role of the formula in establishing costs. Under the building block approach O&M and capital expenditures are assessed separately and in some cases some or all capital expenditures are handled outside of the formula. The separation of capital from O&M expenditures is a key distinction in comparing the two approaches. In contrast, the total expenditure approach combines O&M and capital expenditures under one factor. FBC states that in most cases "the majority of PBR plans end up as hybrid systems where part of the capital expenditures (such as significant sustainment capital) is treated outside the PBR formulas and the rest of capital expenditures and O&M expenditures are determined under indexing formula and the productivity factor." FBC further states that the removal of sustainment capital from the formula results in the large negative impact of infrastructure replacement on TFP being reduced or eliminated. (Exhibit B-1, pp. 29–30)

However, the building block approach does not allow the utility the same amount of flexibility to substitute capital expenditures for O&M, and vice-versa, as does the more traditional revenue cap model.

2.1.2.1 FBC Proposed Formulas for PBR

FBC proposes the following two formulas, one for O&M and one for capital:

O&M Formula:

$$OM_t = OM_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *OM=Operating and Maintenance Expense subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

(Source: FBC Exhibit B-1, p. 52)

Capital Formula:

$$C_t = C_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *C=Capital Expenditures subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

(Source: FBC Exhibit B-1, p. 57)

Note: Fortis also describes two additional components; an exogenous factor (Z) and a flow-through (Y) but does not include them in the formulas.

These formulas provide the basis for calculation of FBC's operating and maintenance expense and capital calculations over the PBR term.

Commission Discussion

There is value in FBC and FEI utilizing the same PBR approach for purposes of consistency. The revenue cap approach has been accepted as applied for by FEI and there is no evidence to suggest that this approach would not be effective for utilities with more stable and growing demand. Accordingly, the Commission Panel accepts the revenue cap approach for FBC

The Commission Panel accepts the building block approach proposed by FBC. It is consistent with the approach taken in previous PBRs, and, as such has a track record. Further, no Intervener takes issue with it.

The Commission Panel also generally approves the formulas proposed. By this we mean that the proposed formula components: an Inflation Factor, a Productivity Factor, Exogenous and Flow-Through Items and a growth term based on average customers may be appropriate for inclusion. Further, the Panel takes no issue with the way Fortis proposes to combine the formula components.

We will examine the various proposed components in these formulas in greater detail later in this section and make determinations on each of these components. In addition, various other components of the FBC PBR proposal will be examined. These include the Earnings Sharing Mechanism, the Efficiency Carry-Over Mechanism, Service Quality Indicators, Review Processes and Off Ramps. These will be reviewed and determinations made. Collectively, these mechanisms will provide guidance and structure to the operation of the PBR over its term.

The PBR Formula Components

2.1.3 Setting the PBR Term

FEI and FBC have applied for a five-year term (2014 to 2018) for their PBRs. Fortis asserts that this is a reasonable term for the PBR Plan for the following reasons:

- It is a commonly adopted term for PBR's in North America;
- It promotes regulatory efficiency by reducing the number of comprehensive revenue requirement reviews; and
- It provides an adequate period of time to allow Fortis to realize cost savings resulting from efficiencies flowing from capital investments and other efficiency initiatives.

(FBC Exhibit B-1, p. 41; FEI Exhibit B-1, p. 45)

Fortis recognizes that a longer PBR plan poses risks to both the utility and its customers but believes that these risks are mitigated by other elements of the plan such as exogenous factors, re-openers and off ramps. It further asserts that the annual and mid-Term review processes will assure transparency and allow regular opportunities to assess the PBR plan.

In their Applications, Fortis draws attention to the B&V Report, which endorses the five-year term as being appropriate given the various elements in the plan. For example:

> "While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable."

(FEI Exhibit B-1, pp. 45–46; FBC Exhibit B-1, pp. 41–42; Fortis Exhibit B-1-1, Appendix D1, p. 36)

Intervener Submissions

CEC's view is that the five-year term proposed by the Companies is not appropriate. CEC states:

> "Theoretically, and as indicated in the AUC decision, the appropriate balance for a PBR plan lies in ensuring the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues become substantially out of sync with its costs or to create considerable gains or losses for stakeholders." (CEC PBR Final Argument, p. 17)

In CEC's view, the five-year term does not strike an appropriate balance as the risks to ratepayers are significant in a five-year term. CEC raises a number of concerns including:

- The claimed 'benefits' set out by Fortis are not supportable;
- There is a benefit to stakeholders if there is more frequent rebasing;
- There is a loss of transparency when costs and revenues are not scrutinized for five years rather than after two years under cost of service regulation;
- There is a loss of some assurance that the Utilities costs and revenues are prudent; and
- The five-year term exposes the ratepayer to:
  - Increased potential for miscalibration of the PBR plan resulting in increased risk;
  - Increased forecasting and estimating uncertainty and error;
  - Increased risk to principles of fair return on capital and recovery of prudent costs; and
  - Increased risk that the costs of the PBR plan will exceed any real benefits.

(CEC PBR Final Argument, p. 17)

CEC notes that PBR terms of three or four years are not unusual, although it acknowledges that those jurisdictions presented in the application are all for five years. CEC further disputes that the cost savings resulting from less frequent revenue requirement hearings are not necessarily a benefit to ratepayers in that revenue requirements have customer benefits and should not be eliminated simply to eliminate the expense of a revenue requirement proceeding (CEC PBR Final Argument pp. 20–21). CEC further suggests that the PBR proceedings will be significantly more expensive than an RRA proceeding and recommends the Commission carefully review the cost effectiveness of PBR relative to cost of service.

CEC challenges Fortis' claims that the longer PBR period is necessary to allow a broader set of efficiency projects to be considered for improving efficiency. CEC contends that efficiency investments may be undertaken within shorter time frames under Cost of Service if properly timed. It also asserts that Fortis has failed to give specific examples of efficiency projects that require a five year time period. CEC recommends that efficiency improvement projects could be brought forward at the Annual Review to allow them to be developed to ensure the required payback was available. This would create greater certainty for both the Companies and the ratepayer (CEC PBR Final Argument, p. 26). CEC also suggests that the issue of payback term could be better addressed through the use of deferral accounts which would not limit payback to any particular term. (CEC PBR Final Argument, p. 23).

With respect to Fortis' claim that the risks to customers and the lack of regulatory transparency under the PBR Plan is mitigated by checks and balances such as the use of exogenous factors, re-openers and off-ramps, and opportunities to review the operation of the plan throughout the term, CEC claims that there is little value to the ratepayer afforded by these checks and balances and they do not provide openness or transparency (CEC PBR Final Argument, p. 25).

CEC recommends that in the event the Commission approves a PBR, they approve at most a three-year term (CEC PBR Final Argument, p.26).

ICG believes that Fortis has not adequately justified a five-year PBR plan and recommends that if a PBR plan is approved, it should have a two-year term.

ICG concludes that:

- Efficiency investments, if any, are not as finely tuned to the regulatory regime as to justify the need for a five year PBR plan; and

- A five-year PBR plan should only be approved for a utility with rate stability closely following inflation. ICG believes this may be the case for FEI but it is not the case for FBC. (ICG Final Argument, pp. 16, 17)

Fortis Reply

Fortis refutes the CEC recommendations for the following reasons:

- Given that a decision will not be forthcoming until the second half of 2014, CEC's recommendation for a three year term is, in effect, advocating a two year term which would restrict the potential for efficiency investments to no greater than would occur under a two-year RRA;
- The shorter time period would also suggest a lower X-Factor providing customers with less upfront benefits;
- The CEC claims regarding increased forecasting and estimating uncertainty and error is erroneous in that PBR formula inputs and flow-through items will be re-forecasted annually in the fall of the preceding year, as opposed to preparing two-year forecasts in the spring before the first year of a two-year Cost of Service test period;
- The AUC 2012 PBR Decision stated:

  > "The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America." (Exhibit B-1-1, Appendix D8, para 836)

- Under PBR, the benefit of embedding cost savings is not lost, it is only delayed. Furthermore, there is an opportunity under PBR to generate greater benefits.

(Fortis PBR Reply, pp. 28–30)

Fortis responds that ICG's view — that efficiency investments are not as finely tuned to the regulatory regime so as to justify a five-year PBR plan – is a backwards approach to analyzing the term. In Fortis' view the PBR is about creating opportunities to find efficiencies. The term selected should maximize these opportunities while balancing this with the need for periodic rebasing. Trying to identify the shortest term necessary to make already identified opportunities viable is not the correct approach. In Fortis' view a shorter term "reduces the power of the incentive for management to find – using economic terms – the best available combination of inputs to produce outputs. There is an opportunity cost to customers associated with a shorter term, which ICG is ignoring."

Fortis makes the following counter-points to ICG's assertion:

- ICG has not cited any evidence in support of the notion that PBR cannot work in the context of a utility that has recently been experiencing rate increases higher than inflation;
- The evidence of Drs. Overcast and Lowry would suggest that the scenario envisaged by ICG merely suggests that the X-Factor for the utility will tend to be negative;
- FBC's recent rate trajectory has been driven by investment in asset replacement and reinforcement projects and the cost of energy to meet customer demand. FBC's proposed PBR plan accounts for such circumstances by excluding lumpy capital from the formula and by flowing through variances in power purchase expenses.

(Fortis PBR Reply, pp. 27–28)

No other Interveners took positions on the length of term of the PBR.

Commission Determination

Both CEC and Fortis agree that a major factor in determining the appropriate length of time for a PBR is to find the balance between a time period that is adequate for the companies to find and pursue opportunities for efficiencies that will benefit both the shareholder and the ratepayer and not being so long as to put either party at risk.

Fortis asserts that the design of the plan puts in place checks and balances, such as regular re-forecasting of certain elements within the PBR formula, annual and mid-term reviews providing an opportunity to assess how well the plan is working, and re-openers and off-ramps to deal with possible failings of the plan. CEC asserts that these checks and balances will be ineffective in protecting ratepayer interests and in addition there are transparency and prudency concerns.

Efficiencies that require significant upfront costs in order to deliver a stream of benefits over a period of years are, in the Panel's view, more likely to be pursued under a PBR with a longer time period. The Panel is not persuaded by the assertions of CEC and ICG that a longer time period for the PBR plan is of little or no value to Fortis' pursuit and implementation of efficiencies. Nor is the Panel persuaded that a five-year PBR plan can only be implemented for utilities with rate stability closely following inflation.

In the Commission Panel's view, the time frame for the PBR plan is appropriately determined by assessing the time period over which the Companies are incented to maximize input efficiencies while the ratepayer and the utility are protected from unwarranted gains or losses. In choosing the time frame for the PBR, we consider the ability of the checks and balances to provide stakeholders with appropriate protection. Elsewhere in this Decision, the Panel directs Fortis to make changes to certain mechanisms, which will strengthen Fortis' proposed checks and balances in order to adequately protect stakeholder interests.

While the Commission Panel finds that with the changes it has directed to the mechanisms that protect stakeholder interests, a five-year PBR term is appropriate, it must be recognized that a substantial portion of year one will have passed without the certainty provided by this Decision. The effect of this would be a PBR term that is only a little over four years. **In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.** This six-year term ending in 2019 should better enable Fortis to find efficiencies that will benefit all parties.

2.1.4 Setting the I-Factor

An inflation, or I-Factor, has been included in the mechanism to provide recognition that utility costs are subject to inflationary costs occurring in the economy. In this Application, Fortis proposes to use a weighted composite I-Factor for O&M with labour at 55 percent indexed to the BC-AWE and non-labour at 45 percent indexed to the BC-CPI which reflects Fortis' current ratios of labour to non labour. These would be based on forecasts for the coming year for both indexes. For BC-CPI, the average of six forecasts is relied upon. Fortis considers the use of a composite labour and non-labour inflation index to be more reflective of Company costs, which have both labour and non-labour components, rather than relying solely on an economy based inflation measure such as CPI.

Moreover, Fortis reports that other jurisdictions have relied upon these two indexes in developing I-Factor estimates.

In selecting these inflation indexes, Fortis considered alternatives on the basis of whether they are:

- Indicative of changes in inflationary pressures that the utility expects to experience;
- Readily available and published by a reputable, independent agency;
- Transparent and easy to understand; and
- Reasonably stable.

Fortis intends to update both the BC-AWE and BC-CPI rates each year as part of the Annual Review process stating that this is more preferable to truing-up forecasts to actual because it more closely reflects the cost pressures of the utility. In explanation, Fortis argues that this methodology applies to both labour and non-labour costs. (FBC Exhibit B-1, pp. 42–44; Fortis Final Argument, pp. 62–67)

Intervener Positions

CEC states that the 55 percent to 45 percent labour/non-labour weighting places too much weight on the labour component particularly for FEI capital. CEC states that the percentage of labour to non-labour for FEI in the last five years has been consistent at "45% to 55% then reversing in 2012 to 55% to 45% and has declined from 54 percent to 46 percent in 2012." Capital has been more inconsistent "in the 22% to 78% range ending in 2012 at 24% to 76%." For FBC, the actual O&M labour to non-labour was 54 percent to 46 percent in 2012, with the capital labour to non-labour ratio 67 percent to 33 percent. (CEC Final Argument p. 35; FBC Exhibit B-11, BCPSO 1.26.3; FEI Exhibit B-6, BCPSO 1.13.2)

In addition, CEC raises a number of issues with the Fortis methodology for determining the I-Factor:

1. Actual vs Forecast Inflation — CEC argues that the Fortis approach results in a consistent bias toward over forecasting. Analysis of the inflation forecasts being used indicates that over the last nine years, the CPI has been over forecast on average by 0.38 percent annually and by 1.4 percent annually on a compound basis. CEC submits that the AUC approach of adopting the previous year's actual is preferable to the Company's approach of using

forecasts, embedding errors and compounding them over time. (CEC PBR Final Argument, pp. 29–33)

2. Impact of Forecast Timing on Adequacy – CEC takes issue with the inflation forecasts they intend to rely upon and the timing of published data. CEC argues that during this proceeding, Fortis' submission of more updated information resulted in a 10 percent reduction in the inflation forecast.

3. CPI Systemically Overestimates Inflation – CEC argues that when using CPI as a measure of inflation, there are 4 systemic biases; commodity substitution, outlet substitution, new goods and quality adjustment bias. CEC cites a number of studies that estimate the bias effect to be 0.5 to 0.6 percent. Dr. Lowry concurs with a CPI bias of close to 0.5 percent and offers the GDP IPI as a solution. CEC submits that Dr. Lowry's evidence on GDP IPI indicates it is the best macroeconomic indicator.

4. Overweighting of Labour to Non-labour – CEC contends that the labour AWE (which is typically higher than the CPI) is over weighted relative to the non-labour portion particularly when it comes to capital. Moreover, when considering the Conference Board of Canada overestimates of CPI and AWE, its estimate of AWE is 100 percent greater than the amount AWE actually exceeds CPI 0.61 to 0.31 percent. It therefore concludes that the proposed methodologies will overestimate inflation. (CEC Final Argument pp. 29–35)

PEG states that if the Commission wishes to use a macroeconomic output price index in the inflation measures for the Fortis utilities either the CPI-BC or the Gross Domestic Product Implicit Price Index times Final Domestic Demand (GDPIPIFDD) for BC is recommended. It indicates that both of these are reflective of local BC conditions. (FEI Exhibit C1-9, PEG Evidence, p. 51) PEG recommends that if the Commission is to approve escalation indexes for capital expenditure budgets, industry-specific indexes are warranted. PEG states that inflation in power and gas utility construction can deviate significantly from macroeconomic measures noting that there has been a slowdown in electricity construction inflation since 2011. In its view, the risk of overcompensation exists if the Commission is to adopt the inflation indexes proposed by Fortis to be applied to capital expenditures. PEG discusses a range of indexes to estimate Canadian construction costs and states "[it] can be seen that the summary EUCPI for power distribution did a fairly good job of tracking the trend in the CSPI for engineering structures…On the basis of this comparison, we recommend the EUCPI for power distribution as the best available measure of the trend in gas utility construction prices." Later in its evidence, PEG suggests that a 50/50 weighting between the EUCPI power distribution and power transmission indexes would be sensible for FBC. Based on a review of the Canadian non-residential building cost price indexes, PEG notes that Vancouver prices lag behind

Canada as a whole by 50 basis points annually and states that it would be reasonable to reduce EUCPI growth rates by a similar amount to reflect the local economy. (FEI Exhibit C1-9, PEG Evidence, p. 51)

With respect to the weighting of labour vs materials, PEG states that care must be taken to ensure the labour cost weighting is equal to the share of direct labour expenses and views the proposed 55 percent as being too high with reference to capital cost or total cost. (Exhibit C1-9, p. 52)

BCPSO argues that the I-Factor should be trued-up to actual because it is uncontrollable and hence, should be flowed through. It notes that if actual prices are different than forecast, the utility will either win or lose and the result will have nothing to do with a gain or a loss in efficiency. BCPSO also takes issue with the Fortis argument that its costs are based on forecast inflation rather than actual inflation due to the timing of purchases. It asserts that actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts. BCPSO takes no position on the use of a composite I-Factor relying upon the BC-CPI and the BC-AWE. (BCPSO Final Argument, para. 41–44)

ICG states that it takes no position on the I-Factor because it does not consider it to have a material impact on rates (ICG Final Argument, p. 23).

Fortis Reply

Fortis submits that the rationale for its proposal is consistent with COS and prior PBR principles and asserts that there is nothing to justify the approach proposed by Interveners. Fortis asserts that CEC has provided no evidence that the BC GDPIPIFDD or BC-CPI alone is more reflective of actual Fortis labour costs than the BC-AWE and CEC's opposition to the use of BC-AWE is because labour indexes rise more quickly than corresponding macroeconomic indicators. In its view, if the Commission were to adopt a measure that reflects labour inflation to a lesser degree, it would result in a bias in favour of customers. (Fortis PBR Reply, pp. 55–56)

Fortis also takes issue with CEC's characterization of labour/non-labour weightings and argues they are more characteristic of the base year and not historical years. In support of this, Fortis points out that the increase in the O&M labour weighting occurred in 2012 when customer care was insourced. This reversed costs between the two categories. In addition, Fortis notes that CEC's percentages do not reflect the contractor labour in the non-labour category. When contractor labour is considered, the 55 percent labour weighting is supported. Fortis also points out that in spite of CEC's opposition to a labour specific inflation measure, its expert, Dr. Lowry "modified his recommended I-X formula for FEI's O&M to include a 55 percent BC-AWE weighting." (Fortis PBR Reply, pp. 56–57)

Fortis does not dispute the average annual variance of 0.38 percent between forecast and actual CPI yields. However, it does argue that the compound annual variance of 1.4 percent for BC-CPI is unsubstantiated and should be disregarded. However, Fortis provides no alternative calculation. (Fortis PBR Reply, pp. 59–60)

Fortis considers forecast inflation as reflective of the cost challenge faced by companies and arguments in favour of a true-up or reliance on the previous year flawed. It points out, in reference to BCPSO's comments, that they are overlooking the fact that the I-Factor serves as a proxy for Fortis' inflation "not the economy as a whole." With respect to CEC's reliance on the previous year actuals, Fortis states that this is just another way of forecasting "which employs a simplifying assumption that the actual experience in the prior year is predictive of the future." In the view of Fortis, relying on the previous year as a proxy for the current year introduces lag rather than being forward looking. Fortis further states that applying the previous year's actuals to future forecasts result in greater under or over estimations of inflation. It provides a graphic demonstration of this showing the two methods and the effect of inflationary changes from 2008 to 2012. (Fortis PBR Reply, pp. 57–59)

Commission Determination

There are two interrelated issues to be addressed by the Commission Panel with respect to the determination of the I-Factor. The first of these deals with the basis on which the I-Factor should be set. Is it appropriate to use forecasts as proposed by Fortis, rely upon the previous year's actuals as argued by CEC or true-up to actual as proposed by BCPSO. The second is what indexes are most suitable to rely upon for the determination of the I-Factor. Related to this is consideration of the labour/non-labour separation. If separated, what is the appropriate weighting for each and whether the weighting ratio should be applied in the same manner for O&M and Capital expenditures?

i) Method to Determine I-Factor

From the evidence presented it is clear there is no perfect way to determine the I-Factor. Therefore, the best that can be expected is to derive a proxy that best estimates the impact of inflation on the Companies for the full PBR period.

The problem with the forecast approach proposed by Fortis is that there will almost always be a variance between forecast and actual. Fortis has not disputed this but has argued that its actual costs are very much influenced by forecast as they often make binding commitments in advance of a given year and these take into account forecasted inflation. The Commission Panel accepts that this may be the case but it is not unique to Fortis as actual inflation measures reflect this spending behaviour on a broader basis. BCPSO makes a similar point as it observes that "actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts." In the view of the Panel, a significant problem with Fortis' proposed reliance on forecast rates of inflation lies in the fact that any variances which do occur are compounded each year. This may not be too serious where there is some assurance that over time these forecast errors will balance out. However, this is not the case. Instead, it is reasonable to assume that over the PBR period future forecasts may be significantly skewed either up or down relative to actuals and, as stated by BCPSO, wins or losses may have little to do with gains or losses in efficiency. **Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.**

The BCPSO approach provides the most accurate measure but suffers from the fact that an actual number is not available until the year has been completed. Both Fortis and its ratepayers require a higher level of certainty as the year progresses and therefore the Panel does not support this approach.

While the approach, proposed by CEC, to rely on the previous year's actual index figures is backward looking and introduces lag, the Commission Panel finds this approach offers some significant advantages. It is based on actual numbers rather than a series of forecasts, none of which are trued up. This approach will ensure that over time the cumulative effect of the I-Factor will be close to actual index numbers. Given the importance of the I-factor on the I-X formula and its impact on future O&M and Capital forecasts over time, the use of actual numbers is of critical importance. While not forward looking, a reliance on the previous year's actual numbers will eliminate the impact of compounded errors that exists in the Fortis proposal. Moreover, the index numbers are available early enough in the year so as to give Fortis and its customers a level of certainty. **Given these advantages, the Commission Panel determines that the I-Factor used in the formula is the actual index results of the previous year**. The Panel notes that this methodology has been employed by the AUC in its PBR.

ii) I-Factor Indexes

The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR. For non-labour expenses, the Panel notes that CPI indexes such as those proposed by Fortis (where an average of six BC-CPI forecasts were used in this proposal) are more commonly relied upon and indeed were approved by the Commission in past PBRs. Moreover, CEC has not presented sufficient evidence to support a move to the GDP-IPI and the Panel is not persuaded that a move away from the more commonly relied upon CPI based indexes is warranted. We do, however, accept that there is a distinction between labour and non-labour costs that is not satisfactorily captured in CPI indexes. Therefore, the Panel accepts the use of the BC-AWE index to capture labour costs and notes that its use seems to be supported by Dr. Lowry.

A matter causing considerable concern among Interveners is whether a 55 percent weighting to labour is appropriate. This issue is raised by CEC, which recommends a lower labour component.

The Commission Panel accepts the explanation of Fortis that FEI's O&M labour costs shifted in 2012 due to the insourcing of the customer care function, which resulted in a 55 percent labour weighting going forward. The Panel also notes that O&M labour costs for FBC have ranged from 54 percent to 58 percent since 2008, which is close to Fortis' proposed 55 percent labour component. **The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.**

When applied to Capital Expenditures the matter is less clear. This is because, as Fortis points out, there is contractor labour in the non-labour line item. When included in the calculation, the inclusion of contractor labour brings the capital labour percentage up to 64 percent from 24 percent, which is higher than the proposed 55 percent for FEI. For FBC, the ratio of labour costs embedded in its capital expenditures has consistently been at 65 percent or higher. **The Commission Panel determines that the 55 percent to 45 percent labour to non-labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.**

The Commission Panel has also considered Dr. Lowry's evidence in support of relying upon industry specific indexes for Capital expenditures as construction costs are not necessarily rising in the utility sector. While this may be the case, the Panel considers that there is insufficient evidence to suggest that capital costs for Fortis' sustainment and other projects are captured by Dr. Lowry's proposed indexes. Hence, a reliance on construction cost based indexes may not be a true reflection of actual costs and the Commission Panel is not persuaded a move to these indexes is warranted at this time.

2.1.5 Setting the X-Factor and Stretch Factor

2.1.5.1 Introduction

Fortis states there are two different approaches that can be used to set the X-Factor, a Pure Total Factor Productivity (TFP) approach and a Hybrid Judgement-based approach. Under the pure TFP approach, the X-Factor is derived from rigorous mathematical models that calculate the growth of total factor productivity. In this approach, the X-Factor is ordinarily defined as the measured industry TFP growth plus an adjustment for any difference between the inflation index used in the PBR index formula and the rate of input price inflation for the regulated sector. (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Fortis describes the following elements as influencing the measured TFP growth:

1. *TFP growth estimator methodology*. Typically either an econometric modelling or an indexed based approach.
2. *The sample of companies***.** As broad a sample as possible. Since it is impossible to ensure the firms in the study are "exactly compatible" it is important to consider the results of the analysis in the context of the specific utility in question and its proposed PBR plan.
3. *The measurement period***.** In general, the most recent data should be used. The length of study periods from other North American jurisdictions is between five and 20 years.
4. *Choice of output measure***.** Ideally a comprehensive set of cost drivers should be used.
5. *Choice of Input Measures***.** Input measures should represent the operating and capital costs associated with the utility. Inclusion or exclusion of particular cost items may add to the bias of TFP estimates.

Fortis also states that "[i]n practice, the X-Factor values estimated through the pure TFP approaches are often adjusted to reflect circumstances of a specific company and by a judgement-based stretch factor." Although Fortis previously asserted that in the pure TFP approach, the X-Factor is derived from 'rigorous mathematical models,' it concludes that the result of a TFP growth study is "thus dependent on expert judgement in a number of areas." (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Under the hybrid judgement approach, "the mathematical derivations of the X-Factor, such as TFP studies, are still used as guidance for the determination of X; however, practical matters such as the actual effects of X on the company's bottom line and expected business conditions during the PBR term are also considered to determine a final measure." Fortis cites research that shows that the parameters that affect a regulated company's costs, revenues and risks should be considered and asserts that these parameters include items such as the PBR term, cost items subject to flow-through in customers' rates, the implementation of other sharing models such as earnings sharing mechanisms and the use of historical or expected performance as a basis for X-Factor estimation. (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 50–51)

Both Fortis and B&V utilize the hybrid judgement approach. B&V's studies resulted in TFP trends of approximately -4.0 percent to -5.0 percent, yet it recommends an X-Factor of 0.0 percent. B&V states that "[c]are must be taken in using the results of any TFP study values because the underlying assumptions of the study may not match the implementation of a proposed plan. The TFP calculated in this study includes an ex-post measure of capital that may differ from the capital treatment that separates a portion of capital such as CPCNs for treatment outside of the plan." (Fortis Exhibit B-1-1, Appendix D2, p. 1)

According to Dr. Overcast "even if you come up with a TFP number, there are some things that you would have to use your judgment on to reflect how that might impact the final X-Factor that you are going to recommend. This judgement, is required because there is no way of 'separating out' CPCN and 'all of the other pass-through costs', from the total cost of any utility in the study" (T3:466). However, B&V provides no specific analysis of its adjustments to the TFP factor. B&V's recommended X-Factor is based on "several features of the overall plan that we believe reduce the negative TFP closer to zero. The 0% X-Factor would include a stretch factor as well"
(FEI Exhibit B-11, BCUC 1.44.1).

Fortis does not accept the recommendations of B&V, and instead applies its own hybrid judgement approach to propose an X-Factor of 0.5% for each utility, stating that this "is well above the range specified in the B&V TFP report." According to Fortis, the reason it proposes to adopt a more challenging X-Factor is to account for Fortis' specific circumstances and the overall design of the PBR plan. In particular, Fortis' proposed PBR plan excludes large capital projects approved as CPCNs, and because the B&V studies cannot separate categories of spending "educated judgement is required to adjust the TFP value for the companies in the study." (FEI Exhibit B-1, pp. 52–53; FBC Exhibit B-1, pp. 48–49).

PEG provides the following formulaic description of its proposed X-Factor:

$$X = MFP^{N} + Stretch$$

stating that MFP^N is a multifactor productivity index that uses the number of customers to measure output. PEG explains that the term stretch reflects an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. PEG adds that "[t]his depends in part on the company's operating efficiency at the start of the PBR plan. It also depends on how the performance incentives generated by the PBR plan compare to those in force for sampled utilities during the index sample period." (FEI Exhibit C1-9, pp. 9, 70)

PEG describes the measure of productivity as:

$$Productivity = \frac{Outputs}{Inputs}$$

and further defines the multifactor productivity index as the change, or trend, in productivity:

$$trend\ Productivity = trend\ Outputs - trend\ Inputs.$$

(FEI Exhibit C1-9, pp. 9, 70)

As can be seen above, while PEG uses the term multifactor productivity (MFP) growth when assessing industry productivity growth, B&V uses the term TFP growth. PEG suggests that MFP growth is the correct term, stating that indexes are sometimes called TFP indexes but are better described as MFP indexes since multiple input categories are considered but some inputs *(e.g.* purchased power) are usually excluded. (FBC Exhibit C6-9 p. 57; FEI Exhibit C1-9, p. 57)

Dr. Lowry agreed that the terms MFP and total factor productivity (TFP) are used interchangeably, but commented that "[t]he reason that I prefer the term Multi-Factor Productivity is when one [does] these studies there are — almost always some utility costs that are excluded from the calculations. For example, even in the Black & Veatch work they excluded the purchase power costs of the utility." (T7:1347)

PEG does not address the issue of judgement based adjustments to the TFP trend results. However, with regard to the exclusion of pass-through costs, it states "Suppose, for example, that expenses for the procurement of energy are not addressed by the indexing mechanism of the PBR plan. These costs should then be excluded from the definition of cost used in the index research. Similarly, the exclusion of a sizable share of routine capex from the indexing mechanism may make it appropriate to exclude some plant additions from the MFP research." (Exhibit C1-9, p. 16)

Commission Discussion

In these Proceedings, the terms TFP and MFP have been used interchangeably. However, we note that in the strictest sense neither study dealt with all inputs so they are both reporting MFP trends. Nevertheless, we will use the terms interchangeably, but if context requires, we will differentiate between the two.

Further, after reviewing the evidence and submissions of parties, the Panel notes differing usage of the terms TFP/MFP and TFP/MFP *change* or *trend*. The four studies (one for gas utilities and one for electric utilities from B&V and from PEG) are designed to measure the *change* or *trend* in TFP/MFP, although the study results have been frequently referred to, by many parties, as TFP/MFP. The Panel will use the term *trend* in TFP/MFP when referring to study results. However, quotations from parties may not always contain consistent terminology.

B&V states that it utilizes the hybrid judgement approach, while PEG appears to use the pure approach. In both cases, the X-Factor recommendations are based on TFP/MFP trend studies. Fortis applies further judgement to arrive at its proposed 0.5 percent. Fortis describes the pure TFP approach as being derived from "rigorous mathematical models that calculate the growth of total factor productivity." However, a considerable amount of judgement was involved in both studies regarding assumptions such as study length, input and output criteria.

The essential difference between B&V and PEG's approaches is that B&V applies a single adjustment to its resulting TFP trend to account for both a stretch factor and the fact that a number of flow-through costs are proposed in Fortis' PBR plans. In contrast, PEG explicitly excludes those flow-through costs from its study inputs. Further, PEG makes explicit its assumptions concerning the stretch factor. This eliminates any need for a judgement based adjustment to the MFP trend result.

In this Decision, the Panel will examine further the underlying assumptions applied by each of the experts, in addition to the judgement-based factors applied by Fortis that underlie its X-Factor recommendations. The Panel will take the following approach:

1. Establish a measure of the MFP/TFP trend upon which to base the X Factor.

   There was considerable disagreement between the two experts concerning TFP/MFP trend study methodology. The Panel notes the submission of CEC that "the Commission has a serious problem with the evidence. The differences of opinion are not straight forward and understandable but are tied into esoteric economic theory and debates about methodology and assumptions, for which only PhD's seem to have perfunctory conclusions" and that "one of the most serious questions for the Commission to resolve is whether or not it is really suitable to impose this morass of complicated debate into the rate making process." (CEC PBR Final Argument, p. 57) We find CEC's comments curious, given the fact that it is referring, at least in part, to its own witness.

   To this, Fortis replies that "The Commission is capable of weighing the expert evidence and coming to a considered decision, and should do so". (Fortis PBR Reply, p. 64). The Panel agrees with Fortis. Accordingly, in establishing the measure of TFP growth, we will examine the report submitted by B&V as part of Fortis' Applications, in addition to the report submitted by PEG for CEC.

   The Panel agrees with Fortis that the result of a TFP growth study is dependent on expert judgement. However, in this proceeding, because there is considerable disagreement between the two experts in many of the study areas, where this occurs, the Commission Panel will assess the differing opinions and we will rely on our own judgement.

2. Apply any adjustments to the TFP that may be required before applying a stretch factor. Fortis states that an adjustment to account for inflation may be required. In addition, the Panel will consider any changes that arise from criticisms made by the parties that we have accepted.

3. Consider, to the extent the Panel finds appropriate, the TFP findings made by the AUC and the OEB as described in the Jurisdictional Benchmarking Report submitted by B&V.

4. Apply a stretch factor. As part of its determination of a stretch factor, the Panel will consider available evidence from the previous PBR period and the X-Factor that was applied

during that period. We agree with Fortis that a stretch factor is judgement based and will use our judgement to determine one that is appropriate.

5. Consider any other parameters that may be appropriate in the determination of the X-Factor. This may include consideration of the elements of Fortis' proposed PBR Plan along with any other specific circumstances of Fortis. This also includes X-Factor evidence from other jurisdictions. Here, the Panel will apply its judgement as to what extent this evidence is relevant to the determination of the X-Factor in this Proceeding.

2.1.5.2 The B&V Studies

2.1.5.2.1 Overview

The B&V TFP trend studies (one for gas utilities and one for electric utilities) were prepared for Fortis. The gas utility database consists of 95 utilities operating in 30 states in the United States (US) for the period 2007 through 2011, which, according to B&V, is the latest available five-year period for the data. The utilities' customer bases range from 86 for Brainard Gas in Ohio to 5,549,399 for the Southern California Gas Company. The sample companies have varied operating histories and include some that have been in existence for over 150 years and others that have been in existence for less than 20 years. There is also a mix of utilities that require transmission mains and those that do not. Pacific Gas and Electric Company has 5,744 miles of transmission main while a number of utilities have none. (FEI Exhibit B-1-1, Appendix D2, p. 2)

The electric utility database consists of 72 electric utilities operating in the US for the period 2007 through 2011, which, according to B&V, is the latest available five-year period for the data. The utilities' customer bases range from 28,372 for Fitchburg Gas & Electric Light Company to 5,278,738 for Pacific Gas & Electric Company. The companies operate in different regulatory environments including bundled and unbundled environments.[1] (FBC Exhibit B-1-1, Appendix D2, p. 2)

[1] In a bundled environment, commodity costs and delivery costs are combined. In an unbundled environment, they are separated.

B&V states that its methodology is based on the use of a production function, which “underlies the estimate of TFP because each level of output corresponds to the different set of inputs required to produce that output.” It states that the “production function defines the relationship between the dependent variable output and the independent variables of capital and labour, which make up the factors of production.” (FEI&FBC, Exhibit B-1-1, Appendix D2, pp. 2, 10)

To calculate inputs, B&V measures the ex-post cost of capital, including return, depreciation and taxes, using Operating Revenue excluding gas costs and all other operating and maintenance expenses. It states that the calculation of this cost is based “on a method that the Federal Energy Regulatory Commission (FERC) refers to as the *Kahn Method.”* The measure of all other costs is “a direct composite measure as reported in the financial reports of each company.” (Fortis Exhibit B-1-1, Appendix D2, pp. 2, 10)

Dr. Overcast has not previously conducted a TFP trend study, although he testified that he had contracted Dr. Lowry to provide such a study (T2:289–290). Fortis states that “Dr. Overcast used his understanding of utility business economics and operations to design a reasonable TFP methodology that addressed shortcomings with applying the traditional TFP model to regulated gas and electric utility industries that do not fit the academic paradigm” (Fortis PBR Reply, p. 69).

B&V’s studies are criticised by PEG on a number of grounds. In particular, Dr. Lowry states that the Kahn method is designed to calibrate the X-Factor given a specific inflation measure and not to estimate the MFP trend. The principle areas of criticism are:

1. Improper approach to Output Measures;
2. Improper approach to Input Measures;
3. Use of arithmetic vs logarithmic growth rates; and
4. Study time period.

(FEI Exhibit C1-9, p. 73)

In many cases, PEG has calculated corrections to B&V's reported TFP trends, to account for these purported errors. However, PEG states that it does not believe that the corrected results are of sufficient quality to serve as the basis for X-Factor calibration. "For example, we are still concerned that the sample period is too short and that costs are included in the study that should be excluded." (FEI Exhibit C1-9, p. 62)

Fortis submits that "[t]he 'corrections', when examined closely, are revealed to be changes in Dr. Overcast's assumptions to match Dr. Lowry's own assumptions." It further submits that "'corrections' are meaningless when Dr. Lowry's assumptions do not approximate reality." (Fortis PBR Reply, p. 74)

The B&V study results are shown in Table 2.1:

Table 2.1 B&V TFP Trend Results

	Gas Utilities	**Electric Utilities**
Average TFP Trend	-4.1%	-4.9%
Range	-3.2% to -4.9%	-3.9% to -5.5%

(Source: Fortis PBR Final Argument, p. 74)

B&V states that the TFP trend results derived from the studies "are theoretically sound and produce results consistent with the logical foundations of TFP analysis and the operating realities of electric [and gas] utilities." In its view, the results are reasonable as the foundation of an electric TFP value determination taking into account the utility specific elements of the plan. (Fortis Exhibit B-1-1, Appendix D2, p. 11)

As previously discussed, Fortis proposes an X-Factor substantially higher than B&V's recommended X-Factor. Fortis acknowledges that the proposed X-Factor is "the one area where B&V and [Fortis] part company." B&V states that based on its review of the factors outside the PBR such as CPCN capital and other provisions, it "felt that even zero is a stretch". B&V regards this additional stretch factor as being more aggressive than is warranted. (FEI Exhibit B-11, BCUC 1.44.13; FBC Exhibit B-1, pp. 43, 48, 49, 53)

Commission Discussion

Of particular concern to the Commission Panel is Fortis' adoption of an X-Factor that B&V feels is "more aggressive than warranted." This suggests to the Panel that the studies' TFP trend results are too low to accurately reflect actual utility industry productivity trends. Accordingly, the Panel will examine the assumptions underlying the B&V TFP trend studies. The Panel will consider further Fortis' hybrid judgement approach to setting the X-Factor in Section 2.2.3.5 of this Decision.

PEG makes a number of comments and criticisms concerning specific assumptions underlying B&V's studies and proposes corrections to the results. These corrections, comments and criticisms also suggest that the B&V Study results are too low. To the extent that these criticisms are valid, this is further indication that B&V's results may be understated.

With regard to PEG's suggested corrections, the Panel acknowledges Fortis' argument that corrections that do not reflect reality are meaningless. However, if a correction is required to ensure that the study results do mirror reality, then those corrections are indeed meaningful. Accordingly, in the following sections of this decision, the Panel will further examine the assumptions underlying B&V's study, including PEG's critique of those assumptions and its proposed corrections.

2.1.5.2.2 Output Measures

For each of its studies, B&V proposes output measures that are a composite of the number of customers and capacity. These output measures are shown in Table 2.2.

Table 2.2 B&V Study Output Measures

Electric	Gas
Composite Output — Weighted by Electric Customers and Substation Capacity 60%/40%	Composite Output — Density-Weighted Number of Customers and Capacity

For the electric study, B&V states that it calculated its output measure (AH[2]) using the following formula:

$$AH = (AG*0.6)+(AA*0.4)$$

where AG = Customers Adjusted for Density and AA = Substation Capacity in MVA. (FBC Exhibit B-1-1, Appendix D2, Schedule 2 LDC Electric Utility Database)

For the gas study, the formula for the output measure (AB[3]) is:

$$AB = (AA*T)+[W*(1-T)]$$

where AA = Customers/Density Index; W = Total Capacity; and T = Distribution Customer Factor (Distribution Main 2" or less/Distribution Miles). (FEI Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database).

In both cases, B&V calculates the output measure for each year using the above formulas and then calculates the trend in output, or "% Output Change by Year"[4] (FEI&FBC, Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database & Electric Utility Database)

[2] AH is the column heading for the output measure in FBC Exhibit B-1-1, Appendix D2, Schedule 2: Electric Utility Data Base.
[3] AB is the column heading for the output measure in FEI Exhibit B-1-1, Appendix D2, Schedule 2: Gas Utility Data Base.

PEG is critical of this approach, stating that:

> "[i]nstead of a proper output trend index, B&V calculated an output *level* index and then calculated its growth rate. In this case, the trend in the capacity index improperly dominated the trend in the number of customers served because of a different numeraire. One indication of the problem is that the estimated electric productivity trend would likely depend on whether substation capacity was measured in kVA or MV." (FEI Exhibit C1-9, p. 60)

B&V did not comment on this issue of the calculation of the output trend.

Commission Determination

The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon. In making this determination, the Panel considered the following example of Allette Inc. taken from B&V's Electric Utility Database. Table 2.3 shows B&V's calculation of the output measure for the years 2008 and 2009 which relies on the capacity measure in MVA.

Table 2.3 B&V Output Measure for Allette Inc. for 2008 and 2009

Year	Density Weighted Number of Customers (AG)	Substation Capacity (MVA) (AA)	B&V Output Measure (AH)
2008	138,818	9,853	61,439
2009	146,486	9,593	64,350

(Source: FBC Exhibit B-1-1, Appendix D2, Schedule 2 Electric Utility Database)

The trend in B&V's output measure is 1.047 (64,350/61,439). In Table 2.4, the Panel recalculated B&V's output measure using capacity measured in KVA.

[4] For the electricity study, % Change in Output 40/60 (column AI) = %Δ in AH. For the gas study, % Output Change by Year (column AC) =%Δ in AB

Table 2.4 Allette Inc. Output Measure based on Capacity Measured in KVA

Year	Density Weighted Number of Customers (AG)	Substation Capacity (KVA)	Output Measure Using KVA
2008	138,818	9,853,000	5,967,327
2009	146,486	9,593,000	5,869,922

(Output measure calculated by the Panel)

The trend in B&V's output measure is now 0.984 (5,869,922/5,967,327). This illustrates that the trend in B&V's output measure is dependent on the units used for capacity.

Table 2.5 Weighted Output Trend based on Trend in each Output

Year	Customers		Substation Capacity		% Change in Customers	% Change in Capacity	Output Trend
	2008	2009	2008	2009			
Using MVA	138,818	146,486	9,853	9,593	1.055	0.974	1.006
Using KVA	138,818	146,486	9,853,000	9,593,000	1.055	0.974	1.006

(% change in customers, % change in Capacity and Output Trend as calculated by the Panel)

Table 2.5 shows the output trend obtained by calculating the trend in each output measure and then combining those trends with a 60/40 weighting as suggested by PEG. The output trend is the same for both cases and thereby is independent of the units used.

The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend. Although capacity and number of customers are both outputs, they have different units and shouldn't be combined. **Accordingly, the Panel finds that B&V's method of calculating the output trend cannot be relied upon.**

2.1.5.2.3 Input Measures

The inputs to the B&V study consist of a capital cost component and a composite cost component that reflects labour, materials, services and rents. B&V states that both inputs are measured on an ex-post basis using actual financial data for each electric utility and because its input measure is cost based, it does not require an index to convert it to a quantitative base. (FEI Exhibit B-1-1, Appendix D1, p. 10)

However, B&V's methodology does require a cost weighting between the capital and composite cost components. For this purpose, B&V uses the following formula to determine the input cost (Y)[5], on which the year-to-year change in input costs is based:

$$Y = D * (1-J) + (G*J)$$

where D is net plant for gas utilities and net plant less production expenses for electric utilities; G is O&M minus gas costs for gas utilities and O&M minus O&M production expenses for electric utilities; and J is the "Operating Ratio", defined as the ratio of G to operating revenue less gas cost for gas utilities and operating revenue less production expense for electric utilities. (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

B&V calculates the input trend in the same way it calculates the output trend. It uses the above formula to calculate an input cost level for each utility for each year. It then calculates the trend in the input cost level (which it labels "%Δ in Y" in its study). (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

CEC explored B&V's methodology, using the example of Alabama Gas from the gas study. The data is reproduced in Table 2.6 for 2007 and 2008.

[5] B&V refer to this as Cost Change. To avoid confusion with the input cost trend, the Panel will refer to this as input cost level.

Table 2.6 Alabama Gas Example

	2007	2008	% Cost Change (2008/2007)
Net Plant (D in the formula above) ($,000)	$660,339	$686,636	3.94%
Operating revenue less gas cost for gas (G in the formula above) ($,000)	$140,186	$139,512	-0.48%
Operating Ratio (J in the formula above)	0.46	0.45	
Input Cost ($,000) Y = D*(1-J)+(G*J)	$498,392	$517,627	
% Cost Change by Year %Δ in Y			3.86%

(Source: Fortis Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base;
FEI Exhibit B-8, CEC 1.81.22)

For this example, the TFP input cost growth, as calculated by B&V is 3.86 percent. However, CEC point out that net plant grows by 3.94 percent (686,366 /660,339 - 1) and O&M by -0.48 percent (139,512/140,186 - 1) Further, the operating ratio suggests that the 2008 cost weights are 45 percent O&M (55 percent capital).

Accordingly, CEC asked Fortis why it is reasonable that the growth in the combined measure is nearly identical to the growth in net plant and not closer to 1.95 percent, which would be obtained by taking a weighted average of the growth rates. (FEI Exhibit B-8, CEC 1.81.22)

Fortis responds that:

> “[t]he calculation of the input change is not an index. The change is based on the quantity of capital as measured by net plant times the price of capital as reflected in the proxy for capital cost applied to net plant. Similarly for O&M the quantity is measured by the dollars multiplied by the composite proxy price as measured by the percent that O&M represents of revenue. It is easy to see that capital has a larger impact on productivity than does O&M ($26 million compared to $700,000). Simply put, the small savings in O&M translates into a cost impact of less than one million dollars while capital costs increase over six times as much. By using the weighted

> average of the two percentage changes, the estimate of TFP would not reflect the relative importance of each component of productivity." (FEI Exhibit B-8, CEC 1.81.22)

PEG is critical of this approach, stating that "the growth of a proper cost trend index is a cost-share weighted average of the *growth* in the component costs. This finesses the problem of cost sub-indexes with different numeraires that make them impossible to meaningfully add up. B&V instead compute cost *level* indexes and then calculate the growth rates in these indexes." PEG points out that in B&V's approach, the trend in net plant value improperly dominates these calculations because net plant value is not a measure of annual cost like the O&M expenses that B&V uses. (FEI Exhibit C1-9, p. 60)

B&V states that there is no problem "with using cost level indexes with numeraries that differ from utility to utility." It further states that:

> "[e]ssentially, this is a concern only because the index method produces dimensionless measures of inputs and outputs so firms can be collected in the index. Since the B&V method treats each utility as its own entity because each utility has its own production technology set and its own input mix for all inputs this criticism is incorrect. This criticism would be correct for an index type measure because indexes use a dimensionless number that is calculated as the cost divided by a price index and is not really an actual measure of the input which has physical dimension such as miles of pipe or electric circuits." (Fortis Exhibit B-45, p.69)

PEG calculates that using proper output and cost trend indexes and using B&V's sub-indexes raises the MFP estimate by the amount of 0.65 percent for gas utilities and 0.27 percent for electric utilities (FEI Exhibit C1-9, pp. 62, 65).

Commission Determination

The Panel has previously found that it is not appropriate to calculate the output trend using an output level index. Instead, a correct approach is to calculate the trend in each output and then combining those trends using an appropriate weighting. The same principle applies to the calculation of the input trend.

B&V's input measure combines operating costs, which are an annual measure, with net plant which is a point in time measure. Thus, B&V combines $ (net plant) with $ per year (operating costs). This is a similar to combining different output measures as previously discussed. CEC calculates an input trend of 1.95 percent, as opposed to the growth rate of 3.86 percent of the input level index, when combining the two inputs with the weighting suggested by B&V. The Panel has no reason to dispute this assertion and notes that an overstated input trend will, all else equal, tend to understate the TFP trend. **Accordingly, the Panel finds that B&V's method of calculating the input trend cannot be relied upon.**

2.1.5.2.4 Inflation in Input Costs

PEG is critical of the tendency of B&V's cost index to overstate costs, stating that using a cost trend unadjusted for inflation materially biases the productivity trend (Exhibit C1-9, p. 58).

In its view, when the Kahn estimate of X is used to estimate the MFP trend and GDPPI is used as the inflation differential, the Kahn estimate is biased by the MFP trend of the economy less the input price differential. PEG states that "[a] Kahn method using US data might nonetheless be used to calibrate the X-Factor of a Canadian PBR plan were the input price differentials and the MFP trends similar in the United States and Canada. However, there is no reason to believe that they are." (Exhibit C1-9, p. 73)

PEG asserts that the input price inflation of energy distributors averaged more than 300 basis points annually in the United States during the years of the study, which materially biases B&V's productivity trend estimate. It considers this a very large error, which "by itself goes a long ways towards explaining the unusually negative trends produced by B&V." PEG calculates an upward adjustment of 3.22 percent to the TFP of gas utilities and 3.35 percent to the TFP of electric utilities to account for this (FEI Exhibit C1-9, pp. 58–59).

B&V argues that, with respect to capital, there is no material bias in its estimate of TFP because it uses net plant to measure capital inputs which is a conservative factor compared to gross plant adjusted for inflation. Regarding the quantum of PEG's proposed adjustment, B&V believes that "given the length of the period any impact or bias would be relatively minor and certainly not the three percent mentioned in the PEG report simply because the net plant measure is far below the gross plant reduced by three percent per year." (Exhibit B-45, p. 68)

Commission Determination

The Commission Panel agrees with PEG concerning the tendency for B&V's cost based input to understate TFP in the event that inflation in the study dataset is greater than the inflation faced by Fortis. B&V doesn't disagree. B&V also doesn't disagree when PEG states that "input price inflation of energy distributors averaged more than 300 basis points annually in the United States." B&V does argue that, with respect to capital, the effect is not material, because of the way it measures capital inputs. The Panel disagrees. With regard to B&V's argument that the input is less because net plant is below gross plant, the Panel notes that a measurement of net plant value is a cost based measurement that reflects the cost of plant additions.

Accordingly, the Panel finds that B&V's cost based input methodology understates the TFP trend.

2.1.5.2.5 Study Period

CEC states that:

> "[i]n choosing a sample period for an indexing study used in X-Factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2011. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. It should also be noted that 2011 was a year of recovery in the United States from the severe recession of 2008- 09." (FEI Exhibit C1-9, pp. 24, 35)

PEG also states that:

> "productivity research for X-Factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run

> productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth." (FEI Exhibit C1-9, p. 15)

In B&V's view, a shorter period is representative of the types of efficiency gains that might be reasonably expected during a five year plan. B&V submits that PEG's

> "concern about the recession's impact is totally misplaced simply because utility management has the responsibility to manage earnings to market expectations regardless of the macroeconomic circumstances. It would be reasonable to assume that if there was any impact of the recession and inflation during this period, utilities would have attempted to seize every efficiency opportunity that would be accretive to earnings." (Exhibit B-45, Rebuttal Evidence to CEC, p. 68)

B&V states that "the shorter period also avoids a number of practical issues such as the impact of restructuring costs that are not properly included in a TFP study since the costs are not included in rates" (Exhibit B-45, Rebuttal Evidence to CEC, p. 69).

B&V also states that there are a number of long-term trends in new technologies that are fully reflected in the TFP trends in the analysis. These include such trends as "directional drilling, live main insertions, joint trenching and so forth all of which represent mature technologies that are incorporated in the TFP results." However, in its view, using a longer period for an indexing study cannot produce a reasonable expected TFP for a short period simply because the longer period is biased by technology and scale impacts that cannot be replicated in the near term. (Fortis Exhibit B2-11, CEC 3.61.1; Fortis Exhibit B2-10, BCUC 3.23.19.2)

B&V also states that

> "[i]t is also important to note that because the customer and capacity measures of output do not suffer from volatility caused by weather or by the business cycle directly, there is much less need for using long historical periods to estimate TFP for use with a much shorter regulatory control period. Using a long period for estimating TFP may include changes in technology that cannot be replicated during the regulatory control period." (FEI Exhibit B-1-1, Appendix D2, p. 10)

In PEG's view, whether or not the output index is cost based and excludes volatile usage variables, the sample period matters when using Kahn's method because an inflation differential is implicit in the calculation and this can be volatile. PEG states that "[it] is notable that in 1993 Dr. Kahn used the longest sample period that available data permitted at the time." (FEI Exhibit C1-9, CEC Evidence, p. 56)

Commission Determination

The Panel agrees with B&V that if there is evidence of an anomalous productivity trend during the study period that is not likely to continue beyond the study period, it may be appropriate to make an allowance. However, B&V has provided no such evidence of any such trend in the period of 1999 to 2011.

With regard to matching the study period to the PBR Plan length, the Panel agrees that a short-term study may be representative of the efficiencies in a five year PBR plan. However, in order for this to be the case, the five-year study period should be in a similar place in the economic cycle that the PBR period will be in in order for the study period to be representative of the PBR period. Since, by definition it is impossible to accurately predict the future, there is no way to ensure that one can pick the appropriate five-year study window to match the economic conditions that a utility will face in the next five years. **The Panel finds that a short study period is not appropriate.**

A long-term study period is superior to a short-term study period because a long term doesn't accentuate any short-term trends. **Accordingly, the Panel finds that a study period should at least be long enough to smooth out any significant short-term economic trends.** In this regard, because the four-year period of the B&V study covered the most severe recession in almost 70 years, the results may be prone to a significant bias.

However, there is no direct evidence of what this bias is. Turning to the PEG studies, the Panel notes that in addition to the 1999-2011 study for gas utilities and the 2002–2011 study for electricity utilities, PEG also conducted studies using a subset of its data, from 2008–2011, which provide results for the same period as the B&V study. MFP trend results from PEG's 2008–2011 studies are compared to PEG's longer-term study results in Table 2.7.

Table 2.7 Comparative MFP Results for Different Study Periods

	1999–2011 gas; 2001–2011 electric	2008–2011
Gas Utilities	0.96%	-0.07%
Electric Utilities	0.93%	0.90%

(Source: Exhibit C1-9, pp. 24, 35)

Looking only at the difference between the results of the two study periods, the Panel considers this a directional indicator that the result of the shorter study period used by B&V tends to produce a TFP trend that is lower than the longer-term trend. **Accordingly, the Commission Panel finds that B&V's TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.**

The Panel notes that this finding that a longer study period is more appropriate is consistent with the finding of the AUC that "using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation." We note also that the two studies conducted by the OEB were eight and seven years. (Fortis Exhibit B-1-1, Appendix D8, p. 67; Fortis Exhibit B-1-1, Appendix D2, p. 14)

2.1.5.2.6 Use of Logarithmic Growth Rates vs Arithmetic Growth Rates

PEG submits that B&V calculates the average annual growth rates in its cost and output indexes by averaging their *arithmetic* growth rates. In its view, this is well known to be an inaccurate method and PEG considers it more accurate to take the average of logarithmic growth rates. Using B&V's composite output measure, PEG calculates that this raises the average annual growth in the MFP estimate by 0.88 percent for the gas study and 0.27 percent for the electric study. (FEI Exhibit C1-9, p. 62)

B&V states that using logarithms in an academic setting would not create an issue whereas many of the participants in a rate case are not trained economists and may be uncomfortable in the rigorous academic environment. It submits that it is important to communicate with all of the parties in a case and since there is no inherent need to use more complicated formulas, its approach seemed to be reasonable and has a basis in historic calculations of index values. It also states that there was no claim that the results were expected to be accurate to three or four decimal places. (Exhibit B-45, p. 69)

Commission Determination

The Commission Panel accepts PEG's evidence that using arithmetic growth rates is an inaccurate methodology noting that B&V does not dispute this. Further, there is no reason to dispute the quantum of the correction proposed by PEG.

We generally agree with the position of B&V regarding the need to communicate with all parties. However, this is not an issue of the third or fourth decimal place. **Given the materiality of this issue, the Panel finds that B&V's use of arithmetic growth rates results in a substantial understatement of the TFP trend.**

2.1.5.2.7 Summary of B&V Studies

Fortis submits that Dr. Overcast's methodology "is rooted in a practical understanding of how utilities operate. Dr. Overcast's methodology yielded results that make more intuitive sense given that the North American utility industry is characterized by mature utilities with significant capital requirements for system replacement." However, it "is not suggesting that Dr. Overcast's approach yields perfect results." (Fortis PBR Reply, p. 76)

Fortis also states that "[t]he Commission does not need to condemn the expertise or the work product of either Dr. Lowry or Dr. Overcast to determine this case". (Fortis PBR Reply, pp. 75–76)

CEC submits that the B&V productivity results are in fact theoretically unsound and produce results that are inconsistent with the logical foundations of TFP analysis, stating that "the failings of the B&V study be acknowledged and that the study be explicitly assigned no weight in the Commission's deliberations." (FEI Exhibit C1-9, CEC Evidence, p. 23)

CEC further submits that "[t]he B&V study has numerous flaws that reduce its relevance in this proceeding to the vanishing point" (Exhibit C1-9, CEC Evidence, p. 58). However, it also states that "the corrected results are consistent with its own estimate of *long* run productivity trends" (Exhibit C1-9, pp. 85–86).

Commission Determination

The Panel has a number of concerns about the B&V studies and is not persuaded that the TFP trend results reported by B&V can be used as a basis to establish an X-Factor.

Dr. Overcast employs a study methodology that is, by his own admission, non-standard. There is no evidence that this methodology has been accepted in any other proceeding. Further, Dr. Overcast has not previously conducted a TFP trend study.

The Panel previously found B&V's use of output and input level indexes inappropriate and cannot be relied upon to generate meaningful input and output trends. We have also made determinations in the areas of input cost inflation, the use of arithmetic vs logarithmic measures and the study length. In all cases, we found flaws in the study methodology that tend to understate TFP trends.

Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.

The Panel notes that there was also considerable argument concerning the following aspects of B&V's input assumptions concerning the input measure:

1. The use of net plant vs. return on net plant; and
2. The omission of depreciation expense from the input measure.

Having not accepted the B&V's study results, the Commission Panel will not consider these issues further.

2.1.5.3 The PEG Studies

2.1.5.3.1 Introduction

PEG's gas distribution MFP trend study, prepared for CEC, is based on data for 64 utilities, including "most of the larger distributors in the United States." PEG states that "[s]ome of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution." (FEI Exhibit C1-9, p. 21)

For the electric utility study, PEG states that "[t]o be included in the study the data were required, additionally, to be of good quality and plausible. Data from 75 companies met these additional standards and were used in our indexing work" (FEI Exhibit C1-9, CEC Intervener Evidence, p. 31).

PEG describes the I-X formula as an Attrition Relief Mechanism (ARM), differentiating between a single ARM, where all spending, capital and O&M is driven by a single formula, and a double ARM, where capital spending is driven by a separate formula than the O&M spending formula. (Exhibit C1-9, pp. 3–5) PEG's study results are shown in Table 2.8.

Table 2.8 MFP Trend Results for PEG Studies

Gas			Electric		
O&M	**Capital**	**Single ARM**	**O&M**	**Capital**	**Single ARM**
0.98%	2.15%	0.96%	1.51%	0.86%	0.93%

(Source: FEI Exhibit C1-22, BCUC 2.4.1; FBC Exhibit C6-21, BCUC 2.4.1. Based on X-Factor recommendations in the Exhibits indicated less the 0.2 included Stretch Factor)

B&V submits that the PEG studies rely on an academic paradigm or academic model and that "[i]n the academic model it is possible to assume away many of the intricacies of actual process. When those assumptions stray as far away from actual facts as in the case of the PEG method the only alternative is to reject the results and give no weight to the estimates of TFP." (Exhibit B-45, pp. 3, 33)

In B&V's view, the academic paradigm cannot be used in a regulatory proceeding. However, B&V is unable to explain why the academic paradigm is prevalent in regulatory proceedings, stating that "[i]t is difficult to explain why the process of estimating TFP in a regulatory setting has not raised these issues in detail (at least in the United States and Canada) previously. In part, it may be that almost all of the work related to estimating TFP has been performed in the academic paradigm without a critical and detailed examination of the issues related to the economics of actual utility operations." (Exhibit B-45, Rebuttal Evidence to CEC, p. 32)

In addition to criticizing PEG for its use of the academic model, B&V also criticizes PEG because it has not provided the "most up-to-date analysis of the academic paradigm," citing the following elements that are not included in the PEG model:

1. The impact of sunk costs on the development of the appropriate TFP values for gas and electric utilities; and
2. Both billed and unbilled outputs in the measure of the output component of the TFP analysis. The principal unbilled output discussed in the literature is a measure of the capacity component of output.

(Exhibit B-45, pp. 20–21)

Commission Discussion

The Panel is not persuaded by Dr. Overcast's argument to reject the academic paradigm and notes that he rejects only some elements while actually arguing for the inclusion of certain elements of the academic paradigm that Dr. Lowry had not included.

We do not consider it necessary to make a determination concerning which elements of the academic paradigm may or may not be theoretically valid. However, the Panel will consider cases where B&V provides evidence that a specific assumption underlying PEG's study, either flowing from the academic paradigm or any other source, is incorrect and it can show that it has a material impact on the results.

2.1.5.3.2 Output Measures

Table 2.9 shows the output measures used by PEG in its study.

Table 2.9 PEG Output Measures

Electric	Gas
number of customers served	number of customers served

Dr. Lowry states that:

> "[t]he number of customers served is a good measure of the number of services, which is a legitimate measure of system capacity. The number of customers typically has the highest explanatory power of the scale variables considered in econometric models of distribution cost…. The number of customers served is correlated with peak delivery capacity because it is dominated by the trend in the number of residential and commercial customers. These customers typically have low load factors." (Exhibit C12-4, p. 5)

Fortis submits that "[b]y choosing to use only one measure of output — net customer growth, Dr. Lowry has an incomplete specification of the output measure and ignores the substantial differences in customer mix that create different output mixes and input mixes to serve customers in different utilities." (FEI Exhibit B-45, p. 4)

Fortis further submits that outputs will be understated (and TFP overstated), by definition, when Dr. Lowry has only accounted for one type of output produced by utilities (customers) and has ignored another (capacity) (Fortis PBR Reply, pp. 68–69).

However, Fortis proposes linking its O&M formula spending to only the number of customers. In that context, B&V believes it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because "[t]he capacity component is not easily measured and would lack transparency if that measure were used. As a result, B&V believes it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula." B&V also states that "there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system." (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, pp. 53, 56)

Commission Discussion

The Commission Panel is not persuaded that PEG's output measure is incomplete or understates the output trend. There is no evidence that this is the case. Further, the Panel notes that, with the exception of FEI's growth capital formula, which uses service line additions, the growth term proposed by Fortis for its PBR formulas uses only customer count. B&V fully endorses that approach, in spite of its position that capacity is a key determinant of utility costs and that it used capacity as an output measure in both of its studies.

2.1.5.3.3 Input Measures

Table 2.10 shows the inputs for the PEG studies.

Table 2.10 PEG Study Inputs

Electric		Gas	
Input Quantity	**Input Price**	**Input Quantity**	**Input Price**
A weighted average of the growth in quantity sub-indexes for labor, materials and services, power distribution plant, and general plant.	A weighted average of the growth in price sub-indexes for these same input groups.	The difference between the growth rates of applicable O&M expenses and a two-category O&M price trend index.	A weighted average of the growth rates in price sub-indexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company's applicable gas distributor cost.

(Source: FEI Exhibit C1-9, pp. 23, 34)

B&V disputes the assumptions used to calculate the sub-indexes in the PEG Report. In its view, this is one of the shortcomings of the academic model. It states that the assumptions required to calculate the inputs are not valid because they rely on the ability to use a single factor (adjusted for regional differences) to convert historic book costs from nominal dollars to real dollars (the deflator) and then rely on a single price index (adjusted only for regional differences in the case of labour) to calculate a measure of inputs (the input quantity). It submits that if either the deflator or the input price is incorrect the results of the PEG method are meaningless and both are incorrect in the PEG analysis. (FBC Exhibit 45, p. 4)

PEG countered that its indexes are chain weighted, cost weighted indexes and it was only in the sub-indexes that apply to the individual categories that fixed weights are used. (T7:1397)

PEG states that it used input price indexes only to calculate the trends in the quantity sub indexes for major input categories such as capital and labour.

> "Considerable care was taken in choosing the price subindexes. All of the price subindexes were specific to the utility industry and all but those for Material and Services (M&S) expenses reflect regional trends. Although the labor price index pertains to multiple utility industries (including, for example, water utilities), the capital and M&S price indexes for gas utilities are specific to that industry and the capital and M&S price indexes for electric utilities are specific to that industry. The labor price index is specific to salaries and wages because pensions and other benefits are excluded from the analysis." (Exhibit C12-4, p. 4)

PEG further states that it:

> "calculated the productivity growth trends of individual utilities and then took their average. The growth in the summary input quantity index for each utility was a cost-weighted average of the estimated growth in the quantity subindexes for that utility. Time-varying and utility-specific cost share weights were used in these calculations where practicable. For example, the summary input quantity index for power distribution has separate subindexes and company-specific cost shares for distribution capital, general capital, labor, and materials and services." (Exhibit C12-4, p. 4)

B&V submits that, in contrast, its approach is much simpler.

> "It does not require the creation of an index for all companies because it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs. The B&V approach assumes that each company is unique and that it is possible to estimate TFP for that unique mix of inputs and outputs by using only each utility as a separate entity and then find a measure of central tendency to estimate the industry TFP." (Fortis Rebuttal Evidence, p. 4)
>
> However, the B&V study methodology considered only price inputs and did not need to convert prices to units of input, so did not actually employ the direct method. PEG does not disagree with B&V, but states that its
>
> "approach to input quantity measurement is more the rule than the exception in productivity research. Even though the input price indexes employed in such research are not a perfect match for the costs they deflate, productivity indexes are widely used in PBR and in macroeconomic research by government agencies such as Statistics Canada. One reason is that the average inflation in the prices of the true basket of goods and services will usually not differ markedly from the inflation in a basket that is more practical to calculate." (Exhibit C12-4, p. 3)

PEG acknowledges that "[i]n the measurement of utility input trends the accuracy of the indirect approach is greater to the extent that the inflation indexes employed track trends in utility prices and use cost shares that evolve over time (so that the index is chain-weighted) and match those of the utility." (Exhibit C12-4, p. 4)

Commission Determination

The Commission Panel is not persuaded that the use of an input cost index in the estimation of TFP trends "cannot produce a meaningful and logical measure of expected TFP for regulated monopolies" as claimed by B&V. We accept PEG's explanation that no such assumptions are relied on. Further, utilities compete for inputs in an unregulated marketplace. They are faced with labour and material price inflation. In order to compute an input quantity index, either the actual inflation measure that applies to the company must be used, or assumptions about inflation must be made.

What is at issue is the relative accuracy of those two different approaches — the 'direct' method that utilizes costs faced by individual utilities as opposed to the index method that utilizes costs averaged over the study sample.

Our view is that both methods can provide meaningful results. However, we do acknowledge that the direct method, which is advocated by B&V, is conceptually more straight-forward than the index method employed by PEG. It does not rely on the study author's ability to create indexes that are reflective of the actual prices and price inflation faced by the companies in the study and is accordingly, to the extent that the actual data is available, likely to be more accurate. However, B&V provides no evidence that such information is available and that employing the direct method using that data would be more accurate.

The Commission Panel questions whether it is practical to obtain input indexes that are specific to individual utilities. In this regard, Fortis proposes to use a fixed weight index that is not specific to the utility industry in its PBR formula as opposed to a measure of inflation that reflects its own specific circumstances.

The Panel does not agree with B&V that "it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs." PEG acknowledges that its methodology will typically not match the cost shares of an individual utility. Instead, it purports to use them to calculate the average productivity trends of a large sample of utilities. In his view, inaccuracies in applications to individual utilities due to improper cost shares tend to average out. We have no reason to dispute this assertion and are not persuaded by B&V's argument that "small errors in measurement across utilities add up to large errors in the measurement of TFP." B&V has not provided any evidence that the differences will be material or that any systemic bias results from small errors of measurement.

The Panel finds PEG's approach to using input cost indexes to calculate input quantities is acceptable. However, although PEG states that "considerable care was taken in choosing the price sub-index," further consideration of those sub-indexes is required. Accordingly, in the next section the Panel will consider the labour price index and in the following section, the construction index.

2.1.5.3.3.1 Input Labour Price Index

PEG states that for the electric study, the growth rate of the labour price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector of the US economy plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole. The quantity sub-index for other O&M inputs was the ratio of the expenses for these inputs to a materials and services [M&S] price index using price sub-indexes for power distributor M&S inputs obtained from the Global Insight Power Planner service. (Exhibit C1-9, p. 74)

For the gas study, PEG states that "[t]he O&M input price indexes summarized trends in the prices of labor and M&S inputs. Price sub-indexes for the M&S inputs of US gas utilities were obtained from the Global Insight Power Planner service." (Exhibit C1-9, CEC Evidence, p. 75)

Fortis submits that the index Dr. Lowry used to deflate labour costs reflects a mix of costs that are too high for the utilities in the sample or FortisBC, which results in an input quantity that is too low and a TFP trend that is too high. This causes the industry to appear more productive in its use of labour than it really is. (Fortis PBR Final Argument, pp. 109–110)

In the view of B&V, the reason PEG adopts this approach to measuring labour cost inputs

> "lies directly in the use of the competitive model to develop the theory that underlies the academic paradigm and the absence of any consideration for the fundamental nature of regulated utilities. Since the labor input measure is not valid absent the assumptions that the technology and mix of labor employed are the same there can be no viable TFP estimate. This is not a problem for competitive industries because all firms use the same technologies and mix of labor types. The PEG reliance on the competitive model assumptions to estimate TFP cannot produce a meaningful and logical measure of expected TFP for regulated monopolies even if regulation over time may equate revenue to cost in the accounting sense." (Exhibit B-45, Fortis Rebuttal Evidence to CEC, p. 12)

PEG replies that "no simplistic or idealized assumptions that might sometimes be invoked in simplified competitive market models used by academicians are required for the analysis." (Exhibit C14-4, pp. 1, 3)

PEG also comments that "[t]he imperfections of off-the-shelf labor price indexes haven't prevented Fortis from proposing to use the AWE as an inflation measure in their RCIs. The AWE that Fortis proposes to use is a fixed-weight index and is not specific to the utility industry at all, much less to the energy distribution sector of the utility industry." (Exhibit C14-4, pp. 3–4)

Commission Determination

The Commission Panel has previously found PEG's use of cost indexes to be an appropriate way to calculate an input quantity. Therefore, the Panel considers that using a labour price index to convert a labour cost into a labour quantity is an appropriate way to establish labour input quantities, provided the price index used is appropriate.

We do not accept B&V's criticism that a labour input is not valid because the assumption that all firms use the same labour mix is only valid in a competitive industry. There is sufficient similarity among distribution gas or electricity utilities to make such an assumption. **In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.** We note that B&V had no need to make such an assumption as it only used cost inputs.

With regard to Fortis' contention that the labour price index that PEG used reflects a mix of costs that are too high for the utilities in the sample, Fortis provides no evidence to persuade the Panel that this is the case. **The Panel finds that no adjustment to PEG's study results is necessary to account for any potential bias introduced by its labour input index assumptions.**

2.1.5.3.3.2 Input Construction Index

The PEG study utilized the Handy Whitman fixed weight construction index to determine the input capital quantity trend. Fortis relied on confidential Exhibit B2-31 Gas Cost Utility Cost Trend Tables (Handy Whitman Indexes) to compare the Handy Whitman Indices for Steel and Plastic Main for the period 1998 to 2001. The index for steel main has a significant increase, while plastic pipe increased to a lesser degree. Thus, the increase in the cost index for steel main is roughly twice that for plastic main. (Exhibit B-45, p. 26)

However, Fortis states that in 1973, 92 percent of the mains installed were steel and 8 percent plastic, but that by 2011, the ratio had changed to 85 percent plastic and 15 percent steel (T7:1521). Given that the relative weighting of the sub-indices are based on 1973 values, Dr. Lowry agrees that using the total plant index assumes that a “fairly large” proportion of the total plant consists of steel mains (T7:1432–1521).

Fortis argues that “Dr. Lowry’s selection of a fixed-weight index with a distant base year is at odds with the views of Coelli et al who emphasize that indexes used in the context of productivity studies should be chain-weighted (not fixed) so that the weights in the ‘basket’ change to keep pace with developments over time” (Fortis PBR Final Argument, p. 29).

Fortis submits that a construction price index that treats utilities as if they still mostly install expensive steel pipe or copper conductor as had been the case 41 years ago will overstate the real price of inputs and overstate Dr. Lowry’s TFP. In its view, this issue alone resulted in Dr. Lowry’s calculated TFP being overstated by orders of magnitude. (Fortis PBR Reply, p. 68)

Elsewhere in its reply submission, Fortis states that “adjusting Dr. Lowry’s X-Factor for this bias alone would result in a significantly lower X-Factor.” (Fortis PBR Reply, p. 61)

Commission Determination

The Commission Panel agrees that a fixed weight index may not reflect the actual cost of utility plant as well as indexes that are weighted to reflect actual utility plant costs. However, with regard to the specific issue of plastic vs steel pipe that Fortis describes, the Panel is not persuaded that the use of a single plant index results in an overstatement of TFP trend by orders of magnitude.

The Panel accepts that in 2011, 85 percent of installed main was plastic and 15 percent steel represents an industry average. However, there is no direct evidence as to exactly what the percentage of installed mains is steel and what percentage is plastic for the specific utilities in the study period. There is also no evidence of how the steel and plastic mix applies to different diameter pipe. Therefore, it is not possible to determine what adjustment, if any is required. However, the Panel agrees that given the rise in the proportion of plastic main generally, and the difference in the price increase for plastic main as opposed to steel main, the fixed weight Handy Whitman Index is likely to overstate the trend in input cost.

For these reasons, the Panel is prepared to consider a modest reduction to the PEG TFP trend result for gas utilities to account for the weighting of construction costs as described by Fortis. **The Panel, using its best judgement, finds a reduction of 0.06 percent to the MFP trend results from PEG's gas utility productivity study to be appropriate.**

There is no evidence on the record concerning copper conductors. Therefore the Panel will not consider this issue any further with respect to PEG's electric utility study.

2.1.5.3.4 Measurement of Capital Cost

PEG states that its approach to the measurement of capital cost "permits its decomposition into price and quantity indexes". It states that it used for this purpose a COS approach to simulate the approach to capital cost measurement in North American utility regulation. This approach assumes straight line depreciation and a book valuation of capital. The trend in the rate of return is a weighted average of the trends in the regulated returns on equity and the embedded cost of debt. (FEI Exhibit C1-9, pp. 18–19)

Fortis submits that the service value of utility plant does not decline steadily, as Dr. Lowry's approach assumes. "TFP will be too high, by definition, if plant that still has full service value is being treated as if it is not required to generate outputs." In its view, this is a key instance where Dr. Overcast has identified upward bias in Dr. Lowry's calculations and it is a matter of "objective fact, not a difference of expert opinion." (Fortis PBR Reply, pp. 68–69)

To illustrate this point, Dr. Overcast testified that "a third of all the main in the ground is over 41 years old, is still in full service and provides full service value, even though it's fully depreciated." (T6:292)

B&V also cites testimony before the Commerce Commission (New Zealand) in 2009 which concluded: "although it is critical – given the characteristics of energy network assets – to use a service potential profile that reflects one-hoss shay[6] deterioration in measuring the *capital input quantity* [the capital cost charges can be based on a range of forms of depreciation provided they satisfy the condition of ex ante FCM. To ensure consistency with regulatory reporting we use return of capital based on straight–line depreciation]." (Exhibit B-45, Fortis Rebuttal Evidence to CEC, p. 27, remainder of quote added from original)

Dr. Lowry states that it is controversial to use an approach to capital that doesn't involve gradual depreciation and notes that the gradual depreciation approach is used in "innumerable studies by federal statistical agencies like Statistics Canada in studies of the MFP trends of the economy." (T6:1333)

He also testified that "studies have shown that when you have a mix of assets of different ages, that as each of them goes *kaput*, they don't all go *kaput* at once. They go *kaput* all the time. And

[6] 1HS refers to a "One-Hoss Shay", which in this context describes a capital asset that exhibits neither input decay or output decay during its lifetime.

actually that is [a] surprisingly similar quantity trajectory to what you would get with a gradual depreciation scenario" (T6:1332).

Dr. Lowry also stated that in his view, the 1HS methodology does not necessarily reflect the cost of replacement capital. He testified:

> "…because you are replacing the old input, and so that's falling off as you add the new one. It's only under cost of service regulation that that would necessarily result in a bump in your quantity. That's the approach that Black and Veatch has disputed. But I think, as I've mentioned, … they kind of go back and forth between the cost of service paradigm in which, thanks to gradual depreciation you do get a bump in capital quantity with replacement, but with the more one-hoss shay approach, you wouldn't necessarily because you are replacing an asset that supposedly until that time was perfectly serviceable." (T7:1359–1360)

In PEG's view "it is not clear that a correctly implemented IHS approach to capital costing would produce MFP trends markedly different from those that I report in [Dr. Lowry's] testimony. Dr. Makholm has used this approach in research and testimony once in Maine and twice in Alberta. The estimated MFP trends he reported in these three studies were 0.44%, 0.78%, and 0.96% respectively." (Exhibit C12-4, p. 3)

Dr. Overcast disagrees, stating that "the basis for that conclusion can't possibly be correct" because the PEG method excludes the 33 percent of all gas main in the US, from their measure of inputs. He bases this estimate on the Pipeline and Hazardous Safety Material Administration's database, which reports the age of these assets. (T1:1509)

However, Dr. Overcast does not suggest a specific adjustment to PEG's TFP trend results to account for the difference between the two methodologies. Further, B&V states that in its study, it used the change in net plant (gross plant additions less annual depreciation expense) and did not adjust this value for inflation. (Exhibit B-45, p. 27)

Commission Determination

The Panel is not persuaded that the results of the PEG study should be adjusted to account for any potential upward bias that may be attributable to the assumption of gradual depreciation in the capital costing approach. Although assuming gradual depreciation may bias the results upward, there may also be an offsetting effect because of the increased maintenance costs associated with aging capital. Further, B&V provides no quantitative analysis of any potential bias and Dr. Lowry states that "it is not clear that including costing would produce MFP trends markedly different" from those reported in the PEG study. The Panel finds no reason to disagree.

The One-Hoss Shay methodology is an element of the academic paradigm that Dr. Overcast is critical of Dr. Lowry for not including. However, the Panel accepts Dr. Lowry's evidence that this element is controversial, and notes that B&V also appears not to take this approach in its study assumptions.

Accordingly, the Panel finds that no adjustments are necessary to account for PEG's capital costing approach.

2.1.5.3.5 Negative Salvage

Fortis submits that capital inputs will be understated (and Dr. Lowry's TFP trend results overstated), "by definition, if there is no recognition given to the material net cost of decommissioning plant (net negative salvage)." (Fortis PBR Reply, pp. 68–69)

Dr. Lowry states this is a reasonable simplification given its small importance (FBC Exhibit C6-15, IR1.3.11).

Commission Determination

B&V provides no quantification of the impact of not including negative salvage, and there is no evidence that indicates that the inclusion of negative salvage will have a material impact on the results of Dr. Lowry's studies. In the absence of any evidence to the contrary, the Panel accepts Dr.

Lowry's assertion that "this is a reasonable simplification given its small importance." **Accordingly the Panel declines to make any adjustments to the study results to account for negative salvage.**

2.1.5.3.6 Input Inflation vs. Output Inflation

Fortis submits that the PEG results are overstated because PEG has not "calibrated" its calculations. Fortis further submits that Dr. Lowry clearly indicates in his evidence that "…when a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends." It also states that:

> "[u]sing an output-based inflation index is problematic because the measure of output inflation already incorporates the effects of economy-wide productivity gains. In other words, BC-GDPIPIFDD already incorporates the effects of the BC economy-wide productivity gains and therefore would not necessarily be indicative of the input price inflation likely to be experienced by the Companies during the plan term. For this reason, the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input."

In Fortis' view, PEG ignores this integral component of its own theory and does not calibrate its X-Factor range recommendations "despite recommending that the Companies use the macroeconomic indicator BC-GDPIPIFDD for its I-Factor" (Fortis PBR Reply, pp. 70–71).

The adjustment suggested by B&V is based on a calculation of growth in revenue per customer provided by PEG (as equation 16 in its filed evidence):

$$\textit{growth Revenue/Customer} = \textit{growth GDPPI} - \begin{bmatrix} \left(\textit{trend MFP}^{\textit{Industry}} - \textit{trend MFP}^{\textit{Economy}}\right) \\ + \left(\textit{trend Input Prices}^{\textit{Economy}} - \textit{trend Input Prices}^{\textit{Industry}}\right) + \textit{Stretch} \end{bmatrix}$$

B&V states that "The term in brackets must be calculated to produce the appropriate X-Factor under the PEG methodology." (Exhibit B-45, p. 60)

Using as an example the X-Factor for capital for gas distribution utilities, B&V calculates the term in brackets as follows:

$$\begin{aligned}\mathbf{GrRevPerCust} &= \mathbf{BC - GDPPIFDD_{Growth}} - [(1.34_{trend\ MFP\ Ind.} - (-0.45_{trend\ MFP\ Econ})) \\ &\qquad + (1.31_{trend\ IP\ Econ} - 3.16_{trend\ IP\ Ind.}) + (0.20_{Stretch\ Factor})] \\ &= \mathbf{BC - GDPPIFDD_{Growth}} - [0.14_{Calibrated\ X-Factor}]\end{aligned}$$

B&V used the following factors in the equation above:

Table 2.11 Adjustment Inputs

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	– 0.45%[31]	1.34%[32]	0.20%[33]
Growth BC-GDPIPI^{FDD}	1.76%[34]		
Trend Input Price	1.31%[35]	3.16%[36]	

31 PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
32 Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
33 Ibid. p.70
34 BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
35 Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]
36 Input Price Trend of U.S. Gas Distributors (1999-2011) from Table 3, Section 3 PEG Evidence

B&V compares the resulting X-Factor to the X-Factor calculated by PEG and describes the difference as the calibration. The resultant calibrations are 1.03 percent for FEI and 0.92 percent for FBC. (Exhibit B-45, pp. 63–64)

PEG comments that "X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend embodied in the GDPPI." It asserts that the MFP trend of the US economy is believed to be fairly brisk, with 1.1 percent average growth in the last 10 years. In its view, this warrants a sizable adjustment to the X-Factor in the US when the GDPPI is used as the inflation measure. In contrast, it states that in Canada, however, the analogous MFP index has declined by 0.45 percent annually on average over the last ten years. (FEI Exhibit C1-9, pp. 13–14)

The AUC considered calibration to the TFP trend, in the event that an output-based inflation measure is chosen for the PBR plan. The AUC Panel found that both components of the approved I-Factors (AWE and CPI) can be considered input based price indexes so no further adjustment was required. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 86–87, 92–94)

Commission Determination

The Commission Panel is not persuaded that the adjustment proposed by B&V is required. The Panel accepts that “the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input.” The calculation provided above by B&V relies on the assumption that the I-Factor is GDPPI, which is a measure of output inflation. However, the Panel has previously approved the use of the CPI and AWE, which Fortis argues are reflective of the input inflation it faces.

Accordingly, the Panel finds that B&V’s proposed calibration is not required.

2.1.5.3.7 Summary of PEG Studies and Comparison to other Studies

2.1.5.3.7.1 The AUC Studies

For its Performance Based Rate Regulation proceeding, the AUC engaged the National Economic Research Associates (NERA) to conduct a TFP trend study applicable to Alberta gas and electric companies. NERA filed its report dated December 30, 2010. The study was based on a population of 72 US electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP trend of the distribution component only of the electric companies. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, p. 59)

In addition to NERA's study, PEG on behalf of an intervener, also performed an MFP trend study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companies as providers of gas transmission, storage, distribution, metering and general administration services. (FBC Exhibit B-1-1, Appendix D8, p. 59)

Table 2.12 AUC Hearing TFP Study Results

Jurisdiction	**TFP/MFP**	**Period Covered**	**Dataset**
Alberta—NERA	0.96%	1972–2009	72 U.S. electric and combination electric/gas companies
Alberta—PEG	1.32% – 1.69%	1996–2009	34 U.S. gas distribution companies over the period of 1996 to 2009

(Source: Exhibit B-11, BCUC 1.1.2)

While acknowledging the value of a separate productivity study focusing on gas distributors, the AUC ultimately did not rely on the PEG report on the basis that: 1) the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria; and 2) PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. Instead, the gas distribution companies that were parties to the proceeding, agreed that NERA's study provided a reasonable starting point for determining the TFP trend for gas distributors." (FBC Exhibit B-1-1, Appendix D8, pp. 86–87)

The issue of the choice of NERA's output index — throughput — was explored in the AUC proceeding. The AUC found that when selecting an output measure, it must be matched to the type of PBR plan. In this case, the AUC accepted the single throughput output index as appropriate as the proposed PBR plans were price-cap plans. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 82–83)

B&V is of the view that "a separate measure of TFP should be used for gas and electric utilities just based on fundamental differences in both the cost and output drivers." (Exhibit B-1-1, Appendix D1, p. 34)

B&V is critical of NERA's TFP academic study methodology, because "the real world of utility operation is not the world of the current academic paradigm. In order to become useful for application in utility regulation, academic studies must be modified to adequately model the key drivers of cost and be more comprehensive in scope by including all of the costs associated with delivery service." (Fortis Exhibit B-1-1, Appendix D2, pp. 31–32)

B&V submits that "the AUC Plan and the NERA study on which it was based should not be used as a basis for the development of a PBR Plan for FortisBC" (FBC Exhibit B-1-1, Appendix D2, p. 39).

CEC asserts that the NERA study "was designed to provide a long term analysis with a long term MFP trend and as such remains consistent with other analysis" (CEC PBR Final Argument, p. 47).

Commission Determination

The Commission Panel agrees with B&V that the NERA study results should not be applied to FEI, as the study only considered electric distribution utilities. However, the Panel considers that the NERA study results have relevance in this proceeding and is inclined to assign them some weight with regard to the electric utility productivity trend. In making this determination, the Panel considered the study length, the dataset used for the study and the output measure relative to the PBR plan the study was prepared for. These issues have all been thoroughly canvased in this proceeding.

The TFP of 0.96 percent approved by the AUC is comparable to the results of PEG's gas utility study presented in this Proceeding.

Given that the PEG AUC study was rejected by the AUC, and has not been tested in this proceeding, the Panel will place no weight on it

2.1.5.3.7.2 The OEB Studies

Table 2.13 OEB Approved TFP Trend Results

Jurisdiction	TFP/MFP	Study Date	Period Covered	Dataset
Ontario 3rd Generation	0.72%	2007	1988-2006	US Utilities
Ontario 4th Generation	-0.33%	2013	2002-2012	Ontario Electric Utilities

(Source: FEI Exhibit B-11, BCUC 1.1.2)

Under the third generation PBR, the OEB decided that due to the lack of a comprehensive Canadian (or Ontario) utilities' financial and operational database, the data from US peer group companies may be used to measure TFP. The study utilized U.S. data for the period of 1988–2006 and calculated a productivity factor of 0.72 percent, which was approved by the OEB in September 2008. However, for the fourth Generation PBR the TFP study was based on Ontario data instead of US data. (FBC Exhibit B-1-1, Appendix D2, p. 14)

A report prepared for the OEB by PEG explained that:

> "the 2012 TFP and econometric results were impacted by three issues with the 2012 data: 1) data were not available on embedded distributors' LV payments made to host distributors; 2) at least 13 distributors adopted international financial reporting standards (IFRS) for the first time in 2012; and 3) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A expense accounts. Of these three data issues, PEG's TFP results were most affected by the clearing of the deferral accounts to expense."[7]

[7] Empirical Research in Support of Incentive Rate-Setting: 2012 Update, September 2013, by PEG, available in Fortis Exhibit B-27, Witness Aid, Empirical Research in Support of Incentive Rate-Setting: 2012 Update Report to the Ontario Energy Board September 2013, p. 25

Commission Discussion

There are issues that, in the Commission Panel's view, limit the applicability to this proceeding of both the third and the fourth generation OEB studies.

The fourth generation study is a study of Ontario electrical distribution utilities. There is no evidentiary basis on which to conclude it is applicable to a gas distribution utility, or how the results can be modified to so apply. Accordingly, the Panel will give no weight to this study with regard to the determination of a TFP trend for the gas utilities. For the same reason, the Panel assigns no weight to the third generation study.

With regard to the applicability of the fourth generation study to electric utility MFP trends, the Panel is concerned that the results may be skewed by the three issues outlined in the PEG report, in particular the issue of clearing the deferral accounts. Accordingly, in the absence of further evidence, the Panel is not prepared to give any weight to this study.

Regarding the applicability of the third generation study to the electric utility MFP trends, the Panel is mindful of the objections of Fortis that the study period is over seven years ago, and will assign no weight to that study.

2.1.5.3.7.3 Summary of PEG's Studies

Fortis submits that "[u]nderstanding what causes a negative TFP value, and its significance, is fundamental to understanding why Dr. Overcast's measured negative TFP values make more sense than Dr. Lowry's large positive values in the present circumstances" (Fortis PBR Final Argument, p. 74).

CEC submits that the Commission has little choice in this debate but to conclude that the PEG research is the superior evidence and methodology by far, not only because of the technical explanations and analysis but because it yields usable results which the B&V evidence clearly does not. (CEC PBR Final Argument, p. 49)

IRG submits that "In this proceeding, the two witnesses clearly disagreed on a surprising number of issues. On balance, the IRG supports the more persuasive evidence of Dr. Lowry." (IRG Final Argument, p. 3)

Commission Determination

The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding. In the Panel's view, with the exception of a small adjustment required to account for the use of the fixed price construction index basket, the underlying assumptions are reasonable and the study length is appropriate. **Accordingly, the Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.**

With regard to Fortis' assertion that negative TFP trends make more sense, the Panel is not persuaded that this is the case. B&V asserts that "there's a lot of infrastructure replacement going on," but does not provide any specific evidence of this replacement for the utilities in either its own or PEG's utility datasets over either study period. The Panel has previously found there are a number of methodology issues, including study period, the use of logarithmic vs. arithmetic growth rates and the way input levels are calculated, that can account for the negative TFP found by the B&V studies.

Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.

2.1.5.4 Stretch Factor

2.1.5.4.1 The Proposed Stretch Factors

B&V states that its recommended X-Factor of 0 percent for each utility "is based on several features of the overall plan that we believe reduce the negative TFP closer to zero." B&V does not quantify the various adjustments it made to the TFP trend results, but states that "[t]he 0% X-Factor would include a stretch factor as well." (FEI Exhibit B-11, BCUC 1.44.13)

Fortis proposes an X-Factor of 0.5 percent submitting that this "exceeds Dr. Overcast's measured industry and economy wide productivity levels by a significant margin, and presents a challenge to the Companies to seek additional efficiencies" (Fortis PBR Final Argument, p. 61). B&V regards this additional stretch factor as being more aggressive than is warranted (FEI Exhibit B-1, pp. 43, 48).

FEI states that "[s]tretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective" (FEI Exhibit B-1, p. 42).

FEI also states that:

> "[i]f the Commission determined a more aggressive 'stretch' productivity factor, FEI would reassess its plans on how to proceed but it is difficult to identify any particular response in the abstract. FEI would not consider the stretch productivity factor in isolation but rather would base its reassessment on the combined effect of the Commission determinations on all PBR Plan elements to determine whether or not the overall impact allowed the utility an opportunity to earn its fair return consistent with regulatory and legal principles." (FEI Exhibit B-8, CEC 1.4.2)

This issue is pursued at some length by ICG. For example, it submits that:

> "FBC has failed to provide any evidence that is relevant to whether it operates efficiently. In the absence of any relevant evidence, the Panel must assume that factors other than efficiency measures and efficient operations all but ensure higher than approved returns for FBC. Mr. Overcast confirmed that conclusions regarding the efficiency of FBC could not be drawn from either 1) the historic PBR Plans, or 2) TFP analysis. The evidence does not even permit the Panel to conclude that FBC is a high or low cost provider as compared to other utilities in BC. FBC consistently objects to such evidence being filed, and now must accept the consequences of such objections." (ICG Final Argument, p. 4)

Commission Determination

The Commission Panel agrees with ICG that there is a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**

In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. As a result of this consultation, the Panel expects that agreement be reach on the broad terms and parameters of the study**. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.**

2.1.5.4.2 PEG's Recommendation

PEG states that:

> "both Fortis units have operated under PBR in the past. However, the PBR plans for both companies exempted a large portion of capital cost from the force of PBR, and both companies have now operated for a few years under cost of service regulation. Neither company has presented convincing evidence of superior operating performance in this proceeding. On the basis of the available evidence, it is reasonable to assume that each company is an average cost performer."

Based on this observation and the proposed 50-50 earnings sharing mechanism, PEG recommends a stretch factor of 0.2 percent. (FEI Exhibit C1-9, p. 70)

2.1.5.4.3 Previous Fortis PBR Plans

The parties involved in the NSP for FEI's previous PBR agreed that "linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009." (FEI Exhibit B-1, p. 35)

For FBC, the 2006 Negotiated Settlement Agreement established an X-Factor of 2 percent for 2007, 2 percent for 2008, and 3 percent for 2009 (if the term of the PBR was extended). For the period 2009–2011, the Parties to the 2009 NSA agreed that some linking of the productivity factor to BC CPI would be beneficial. As such, the 2009 NSA established X-Factors of 1.5 percent for 2010 and 2011 when BC CPI is less than 3 percent, with the X-Factor increased to offset any increase in BC CPI above 3 percent. (Fortis Exhibit B-1-1, Appendix D1, p. 25)

FEI submits that:

> "[a] utility's past history with PBR plans may also be considered for X-factor determination. Ordinarily, utilities with no previous experience with PBR plans (as is the case for Alberta's utilities) may have a better chance to improve performance at a faster rate than the industry average (the inefficient utilities have more —low-hanging fruit or cost savings that can be implemented easily). This may justify a higher than usual X-factor used in Alberta in comparison to a utility like FEI that has years of recent experience with PBR and fewer available productivity improvement opportunities." (FEI Exhibit B-11, BCUC 1.6.1)]

However, Fortis also argues:

- First, neither of the PBR experts in this case, including CEC's own expert, used the previous negotiated X-Factor as the starting point for their recommendations. Rather, Drs. Lowry and Overcast both based their recommendations on industry productivity levels, which is consistent with what is done in other jurisdictions where PBR has not been negotiated. The TFP study undertaken by Dr. Overcast yielded a negative TFP. FBC's prior history under PBR only came into play in determining the stretch factor. Drs. Lowry and Overcast agreed that the stretch factor should decline over time to recognize diminishing returns.
- Second, the fact that the X-Factor averaged 2percent during the last FBC PBR is not a rationale for adopting the same X-Factor today. TFPs have been declining, and accelerated infrastructure replacement continues. PEG recently calculated a negative TFP in Ontario, and even Dr. Lowry's recommendation and NERA's values in Alberta fall well short of the number advocated by ICG. (Fortis PBR Reply, p. 75)

2.1.5.4.4 Stretch Factors from Other Jurisdictions

The AUC approved a stretch factor of 0.2 percent be used by the respective Alberta distribution utilities in their PBR Plans. It was assumed that the transition to PBR from COS regulation would produce immediate expected increases in productivity growth. As such, the purpose for the addition of the 0.2 percent stretch factor was to share between the companies and customers these immediate expected increases in productivity growth. (Exhibit B-1-1, Appendix D2, p. 5)

The OEB:

> "concluded that there are considerable variances between existing efficiency cultures of the utilities and that a single stretch factor for all distributors is not appropriate. Therefore, two benchmarking evaluations were considered to divide the Ontario's power distributors to three efficiency 'cohorts' where each cohort was given a specific stretch factor. While grouping of distributors into three cohorts was based on solid benchmarking techniques, the determination of stretch factors values was mainly subjective and based on the OEB's judgment." (FEI Exhibit B-1-1, Appendix D2, p. 14)

Table 2.14 OEB Stretch Factors

Characteristic	Cohort One	Cohort Two	Cohort Three
Criteria for cohort groups	Statistically superior econometric benchmark and (2) top quartile result in the unit cost index benchmark	Superior in one methodology and inferior in the other one	Inferior in both benchmarking techniques
Stretch factor value	0.2	0.4	0.6

(Source: Exhibit B-1-1, Appendix D-2, p. 14)

Commission Determination

In the absence of a benchmarking study, the Panel considers the following:

1. Fortis' proposed stretch factor of 0.5 percent, which is in addition to the stretch factor embedded in B&V's recommended X-Factor;
2. Dr. Lowry's suggested stretch factor of 0.2 percent; and
3. The range set by the OEB of 0.2 percent to 0.6 percent.

A stretch factor in excess of 0.5 percent is substantial. It is, for example, considerably larger than PEG's proposed stretch factor of 0.2 percent. When compared to stretch factors approved by the

OEB, this would put Fortis in the range of the least efficient utilities. This is contrary to FEI's assertion that "FEI has already realized significant efficiencies under its previous PBR that can only be achieved once" and that "efficiencies that can be expected to be achieved under PBR decline over successive PBR terms" (FEI Exhibit B-53, Panel 2.1). Accordingly, the Panel gives no weight to Fortis' proposed stretch factor.

The Panel agrees with Fortis that past history may be considered. However, the Panel also agrees that a utility that has years of recent experience with PBR may have fewer available productivity improvement opportunities. Accordingly, stretch factors from recent previous PBR periods could suggest upper limits to stretch factors going forward.

Upon reviewing Fortis' previous PBR Plans, we note that in all cases except for 2007 to 2009, inclusive, the X-Factor varies, based on forecast CPI. This is a different approach than proposed in this Application, where the X-Factor is fixed, regardless of inflation. The Panel does not find it appropriate to impute a stretch factor under these circumstances. To impute a stretch factor from FBC's negotiated X-Factors of 2 percent for 2007 and 2008, and 3 percent for 2009, the Panel assumes a TFP of 0.93 percent. This results in a stretch factor of a little over one percent for 2007 and 2008, and a little over two percent for 2009. However, given that FBC has been in a PBR regime for a substantial amount of time, it would not be appropriate to continue with the same stretch factor and a reduction is appropriate. Further, considering that FBC has been in a PBR regime longer than FEI, a lower stretch factor for FBC is appropriate.

Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.

2.1.5.5 Setting the X-Factor

As previously set out, in determining the X-Factor, in addition to considering the TFP trend and the stretch factor, the Panel will consider the adjustments that Fortis proposes to account for its specific circumstances and also apply our own judgement to determine if any additional adjustments are required.

2.1.5.5.1 Fortis' Proposed X-Factor

Fortis proposes an X-Factor of 0.5 percent, suggesting that, although it is substantially higher than B&V's recommended X-Factor, it is reasonable. In support of its proposed X-Factor, Fortis cites the following:

a. Accelerated trend in asset replacement in the gas and electric utility industries. This has resulted in a more negative TFP trend than is attributable to Fortis, because Fortis proposes to exclude significant portions of capital from its formula spending.

b. PEG's recommended X-Factors for Ontario utilities is close to zero; and

c. A high-level comparison with illustrative revenue requirements forecasts show that the proposed 0.5 percent X-Factor, along with the proposed composite inflator, will result in rates that are lower than the rates under a cost of service model.

(FEI Exhibit B-1, p. 53; FBC Exhibit B-1, p. 49; Fortis Reply, p. 72)

Fortis also submits that "it can be argued that the X-Factor for a PBR plan with an earnings sharing mechanism is less significant than under a plan with no earning sharing mechanism." (FEI Exhibit B-1, p. 51, FBC Exhibit B-1, p. 47)

ICG submits that "[a]ssuming the Panel approves a PBR Plan, the ICG recommends an X-Factor of 2% to match the average X-Factor during the last PBR Plan" (ICG Final Argument, p. 23).

2.1.5.5.2 Single ARM vs Double ARM

In PEG's view, the single ARM approach has a more solid empirical foundation provided that the capital cost tracker is redesigned along more conventional lines. PEG believes that a single ARM, applicable to most of the companies' revenues, and separate ARMs for capital and operation and maintenance expenses are both potentially workable for the Fortis companies. However, in its view, an issue with the single ARM approach is the unusually large amount of capex that would be separately addressed by a cost tracker. PEG recommends tightening the eligibility standards for the capital cost trackers to mitigate this issue. (FEI Exhibit C1-22, BCUC 2.3; FEI Exhibit C1-22, BCUC 2.4.1)

FEI states that although the costs are looked at separately to allow more appropriate cost drivers to be assessed from each side, its building block model proposes the same X-Factor for each block. It further submits that a single X-Factor is what Dr. Lowry refers to as a single-arm approach, which is the same approach that is taken in "all of the other plans that the Commission has evidence before it on." (T8:1397)

2.1.5.5.3 Adjustments for Excluded Capital

Fortis proposes to exclude all CPCN capital from its formula driven spending envelope. For FEI, this includes all capital over $5 million and for FBC all capital over $20 million and in some cases, capital projects of any size below $20 million. PEG estimates that this amounts to 30 percent of all capital expenditures for FEI and 40 percent for FBC. (FEI Exhibit C1-22, CEC Response to BCUC 2.4.3)

PEG states that there is no established methodology for making such exclusions. However, when asked to provide study results assuming exclusion of similar amounts of capital, it reported an increase in the single arm MFP trend to 1.98 percent. In its view, "[t]his result would be pertinent for the calibration of an X-Factor for a comprehensive revenue cap index, assuming that CPCN costs flow through a tracker." (FEI Exhibit C 1-13-1, CEC Response to BCUC 1.13.3)

2.1.5.5.4 X-Factor Evidence from Other Proceedings

X-Factor evidence was also presented from Alberta and Ontario. In Ontario, X-Factors are either the result of negotiated settlements or are calculated as the sum of the TFP trend and a stretch factor.

Fortis submits that when reviewing the X-Factors in other jurisdictions, the timing of these decisions is important when there is evidence of accelerating asset replacement occurring in the last five years that is expected to continue during the PBR term. Apart from Alberta's X-Factor of

1.16 percent, all of the other cited X-Factors over 1.0 percent were set at least five years ago, presumably based on even older information. (Fortis PBR Reply, p. 72)

With regard to the AUC's X-Factor, Fortis submits that it is based, "by and large, on expert evidence that used the same academic assumptions used by Dr. Lowry that do not properly reflect actual productivity." It further states that "[b]oth experts in this proceeding also considered the NERA analysis relied upon by the AUC to be incorrect." (Fortis PBR Reply, p. 72) However, Dr. Lowry stated that although there were "lots of little technical errors" in the NERA study, he does not suggest that the result is upward-biased (T7:1386–1387).

Commission Determination

The Commission Panel has the following comments concerning the three factors Fortis cites in support of its proposed X-Factor:

a. **Accelerated asset replacement trend**. This issue arises because B&V and Fortis attribute the negative TFP trends from the B&V studies to accelerated asset replacement. The Panel has previously determined that shortcomings in the study methodology may account for the negative TFP trends. Further, the Panel has determined that it will not accept the results of the B&V studies. Accordingly the TFP trend results from these studies cannot be used as a basis for even the hybrid judgement approach. We will not consider the issue of asset replacement any further in making our X-Factor determination.

b. **PEG's Ontario X-Factor Recommendation**. In our review of the OEB proceedings, the Panel found that the principle reason the MFP trend was close to zero was due to the OEB requirement to clear deferral accounts. As such, the OEB result has little relevance in this proceeding. The Panel will not consider this issue any further.

c. **Comparison to COS Rates**. We do not consider an "illustrative revenue requirements forecast" to be a reasonable basis on which to make an X-Factor determination. The "illustrative forecast" has not been adequately tested and, as such, may be prone to error and bias. It cannot be viewed as a cost of service requirement for the next five years.

With regard to Fortis' statement concerning the reduced importance of the X-Factor if the PBR plan includes an earnings sharing mechanism, it is unclear to the Panel how, if at all, this may have influenced either B&V's or Fortis' judgement based adjustments. It is not clear to the Panel what is meant by “reduced importance”. It is not appropriate to use the presence of an ESM to justify an X-Factor that may, for example, be too low. In that circumstance, the X-Factor would enable the utility to over recover its costs. While sharing that over-recovery with its customers does mitigate the effect of the over recovery somewhat, it is not sufficient justification to use an X-Factor that is understated.

For all of the above reasons, the Panel is unable to approve the X-Factor as applied for.
The Panel accepts PEG’s assertion that the single ARM has a more solid empirical foundation. In addition, the Panel agrees with Fortis that its proposed plan has the characteristics of a single ARM approach. However, the Panel is concerned that because of this proposed treatment of capital expenditures, an adjustment to the single ARM X-Factor may be required.

The Panel is mindful of the comments of both experts regarding excluded capital. We agree that if significant capital spending is excluded from the PBR formula driven spending envelope, adjustments to the formula may be necessary. B&V included this consideration in its upward adjustment of approximately 4 percent but, as discussed previously, does not provide any details concerning that adjustment. Accordingly, it is not possible to discern the directionality of the adjustment to allow for excluded capital, although the magnitude of the gross adjustment suggests that the effect of excluded capital may be to drive the TFP trend upwards. The results reported by PEG are also suggestive that its reported single ARM MFP trend is too low when applied to a PBR plan with a significant amount of excluded capital. **Accordingly, if significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.**

The Panel considers the matter of excluded capital further in Section 2.3.5 of this Decision. There, the Panel finds that the CPCN based exclusion criteria proposed by Fortis is not appropriate and invites further submissions from parties on the issue of the threshold for excluded capital. Accordingly, **the Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.**

Having considered FEI's special circumstances and the overall design of the PBR plan, no further adjustments are required at this time.

Accordingly, the Commission Panel has determined the following X-Factors should be applied to Fortis' proposed PBR formulas for the PBR term:

Table 2.15 Approved X-Factors

Utility	TFP	Stretch Factor	X-Factor
FBC	0.93	0.1	1.03
FEI	0.90	0.2	1.10

2.1.6 Exogenous or Z-Factors

Fortis proposes that exogenous factors, which it characterizes as "non-controllable and unforeseen costs/revenues," be flowed through to rates during the PBR term (FEI Exhibit B-1, p. 70). The Companies state in their Final Argument that "it is not necessary, and is impractical, to be overly prescriptive in advance as to mechanisms for addressing exogenous factors"; therefore, Fortis submits that it will notify the Commission and stakeholders of exogenous events in a variety of ways, including through the Annual Review process or through a letter to the Commission, depending on the type of exogenous factor event (Fortis PBR Final Argument, p. 48). Fortis states that the recovery of exogenous factor events in rates may be achieved through a variety of mechanisms such as flow-throughs, deferral accounts and true-ups. (Exhibit B2-11, CEC 3.29.7)

The Companies provide a list of exogenous factors in their Applications. This list serves as an example of types of events that fall under the classification of "exogenous"; however, the Companies submit that this list is not exhaustive but merely serves as an example of the types of events that would lead them to apply to the Commission for exogenous factor treatment. The exogenous factors listed in the Applications are as follows:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;

- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes and changes to cost of capital).

Certain of the above exogenous factors, including catastrophic events, bypass or similar events, and major seismic incidents are further explored in the BCUC IR 3.22 series of questions in Exhibit B2-8 of the Fortis PBR proceedings. For instance, Fortis described a bypass event as a situation where a customer may be physically taking service from another supplier while remaining within the service territory and thus making no use of the Company's facilities, or where it has become economic to leave the Company's service area for another location because of rate or other utility policies that have caused the costs to the customer to exceed its standalone costs. Fortis submitted that a bypass event qualifies as exogenous because, unlike in an unregulated environment, the Company is not free to adjust its prices between its marginal cost and the standalone cost of its customers.

Fortis does not propose to apply any criteria or a materiality threshold to exogenous factor events. Instead, the Companies submit that "[w]hile, in principle, all unforeseen events that are beyond the Companies' control should be treated as exogenous, the Companies' evidence is that they may choose not to apply to recover amounts related to small events that do not have an impact on the Companies' ability to serve its customers and that do not have a material cost impact." (Fortis PBR Final Argument, pp. 47–48)

Fortis' proposed treatment for exogenous factors is consistent with the Companies' approach in previous PBRs; however, it differs from the approach taken by other Canadian jurisdictions under PBR. The other jurisdictions take a more prescriptive approach to the definition of exogenous factors through the establishment of a set of applicability criteria and a materiality threshold. This provides for greater clarity when determining if an event is eligible for exogenous factor treatment. (Fortis Exhibit B2-11, CEC 3.27.2)

Materiality

Fortis submits that the Commission should not impose a materiality requirement because "the cost increases or decreases arising from exogenous factors are non-controllable costs, and are therefore prudent by definition." The Companies further submit that any costs/revenues arising from non-controllable events would be recoverable in rates under cost of service-based ratemaking without any materiality threshold; therefore, the same logic should apply to PBR-based ratemaking. (Fortis PBR Final Argument, p. 47)

In response to CEC IR 3.32.6, Fortis states: "Exogenous factors should, in principle, flow through. However, when the changes are *de minimis* management may not seek recovery." Fortis further states that the "decision not to apply for recovery of a small cost must be treated as a practical determination, appropriately made by the Companies at the time and not by the Commission in advance" (Fortis PBR Final Argument, p. 48).

Fortis indicates that if the Commission determines that a materiality threshold is required, it should be based on a dollar value as this would be simpler than looking at ROE impact. Fortis referenced Ontario's thresholds which are in the range of $1 million to $1.5 million (T4:801) and further states that the Commission should take into account the relevant size of each of the Companies if the Commission decides to establish a materiality threshold (T4: 803).

Other Jurisdictions

Table 2.16 shows the criteria and materiality threshold established by the AUC:

Table 2.16 AUC Treatment of Exogenous ("Z") Factors

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
ALBERTA		
Z-Factor *(Unforeseeable events outside the control of the company, for which the company has no other reasonable opportunity to recover the cost within the PBR formula)*	1. The costs/impact of event must be attributable to events outside management's control. 2. The costs/impact of event must have a significant influence on the operation of the company 3. The costs/impact of event should not have a significant influence on the inflation factor in the PBR formulas. 4. The costs/impact of event must be prudently incurred. 5. The impact of the event was unforeseen (Z-Factor)	40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established

(Source: Exhibit B2-11, CEC 3.27.2, p. 67)

In response to CEC 3.31.1, Fortis provided the following assessment of the AUC criteria established for Exogenous or "Z-" Factors:

- Fortis considers criteria 1 and 5 to be implicitly established within the Companies' own proposals, as evidenced by the Companies' description of exogenous factors as "non-controllable" and "unforeseen" within their Applications.
- Fortis does not agree with criterion 2 and submits that "placing a materiality limit is most likely to deny prudent cost recovery and increasing the underlying risk."
- Fortis does not support criterion 3 because it considers it improbable that even a substantial rise in the inflation rate for the I-Factor in the PBR Formula could recover the costs of exogenous factors such as catastrophic events, major seismic incidents, and Acts of war, terrorism or violence. Fortis further asserts that the aforementioned exogenous factors are likely to have substantial impacts on economy-wide input prices.
- Fortis considers criterion 4 to be "unnecessary" because prudency in all expenditures, not just exogenous costs, is required by regulated utilities. (Exhibit B2-11, 3.31.1)

Table 2.17 shows the criteria and materiality thresholds established by the OEB:

Table 2.17 OEB Treatment of Exogenous ("Z") Factors

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
ONTARIO		
4th GENERATION IR		
Z-Factor *(treatment for unforeseen events)*	1. Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived. 2. The amount must have been prudently incurred. 3. The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor	1. Utility with Revenue Requirement less than or equal to $10 Million: $50 thousand Threshold 2. Utility with Revenue Requirement greater than $10 Million but less than or equal to $200 million: 0.5% of distribution revenue requirement Threshold 3. Utility with Revenue Requirement of more than $200 million: $1 million Threshold
EGD and Union (2008-2012 plans)		
Z-Factor *(non-routine events that were not otherwise recovered in the annual adjustment mechanism)*	1. The event must be causally related to an increase or decrease in the distributor's cost 2. The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate 3. The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism 4. The cost increase/decrease must be prudently incurred	The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of $1.5 million.

(Source: Exhibit B2-11, CEC 3.27.2, pp. 67–68)

Fortis provided an assessment of the OEB criteria during the Oral Hearing. The Companies consider criterion 1, which requires that amounts be causally related to the Z-Factor event, to be a given and therefore not necessary to be explicitly established as a criterion. Fortis also considers criterion 2 regarding prudency to be an unnecessary criterion since all costs incurred by the utility must be prudently incurred. Fortis does not agree with the OEB's third criterion establishing a materiality threshold for the reasons discussed previously in the analysis of the AUC criteria. (T4:805)

<u>Intervener Submissions</u>

CEC submits that Fortis' proposal for treatment of exogenous factors provides the Companies with considerable discretion and that the proposal is misaligned with customer interests (CEC PBR Final Argument, p. 151). CEC identifies four key issues with Fortis' exogenous factor proposal:

1. Inadequate definition and lack of applicability criteria;
2. Lack of materiality clause;
3. Prudency not explicitly required; and
4. No obligation for "exogenous" savings to be brought forward on an equal footing.

CEC proposes the following criteria for exogenous factors:

1. Attributable entirely to events outside the control of a prudently operated Utility;
2. Directly related to the Exogenous event and clearly outside the base upon which the rates were originally derived;
3. Mitigated to the greatest extent by the Utility;
4. Prudently incurred; and
5. Greater than 30 basis points of ROE for the Utilities per year for exogenous events.

(CEC PBR Final Argument, pp. 157–158)

CEC submits that it is appropriate to establish criteria for determining whether or not an event is eligible for exogenous factor treatment so as to distinguish between costs that are justifiably extraordinary and costs that would otherwise be expected to be incurred under the PBR formula-driven spending. (CEC PBR Final Argument, p. 154)

CEC recognizes that there is an expectation of prudency in all expenditures but it still considers it necessary to include prudency as an explicit criterion. CEC submits that "as Z factors are explicitly intended to address extraordinary circumstances it is not unreasonable for the costs to be challenged." (CEC PBR Final Argument, p. 156)

CEC further recommends that Fortis be required to disclose all exogenous events that result in benefits to the ratepayers at the annual review. (CEC PBR Final Argument, p. 158)

No other interveners made submissions on Fortis' proposed treatment for exogenous factors.

Fortis Reply

The Companies take issue with CEC's proposed criterion 3 which states that exogenous factors must be mitigated to the greatest extent by Fortis. The Companies submit that they are governed by the prudence test and any exogenous factor will be tested under their proposal. The Companies further submit that a guideline that is "focused on outcomes rather than prudent conduct, which CEC appears to be advocating, is contrary to the UCA" (Fortis PBR Reply, p. 45).

Fortis submits that CEC's proposed materiality threshold of 30 basis points of ROE is large and could impair the Companies' opportunity to earn a fair return. Fortis submits that to put CEC's proposal in context, the proposed materiality threshold is equivalent to greater than $4 million of FEI's Operations and Maintenance (O&M) expense and is likely greater than $45 million of FEI's capital. (Fortis PBR Reply, p. 44)

Commission Determination

The Panel finds it necessary to include exogenous factors as part of the Companies' PBR plan in order to protect both the ratepayers and the shareholders. However, the Panel agrees with CEC that the Companies' proposal for exogenous factors is inadequately defined. **The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:**

1. **The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;**
2. **The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;**
3. **The impact of the event was unforeseen;**
4. **The costs must be prudently incurred; and**
5. **The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.** This is further defined in the section below**.**

The Panel considers the establishment of the above criteria necessary for transparency and greater clarity for all stakeholders as to why an amount is being brought forward for exogenous factor treatment. The criteria create an objective measure for assessing whether a potential event should appropriately be treated as an exogenous factor as opposed to solely relying on the Companies' judgment as to whether or not an amount should be brought forward for review by the Commission. The certainty provided by these criteria will improve the alignment between shareholder and customer interests.

Materiality

The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time. Establishing a materiality threshold also reduces the reliance on Fortis' judgment and instead creates a more transparent and objective process for determination of exogenous factor applicability.

In determining the appropriate materiality threshold, the Panel considered the balance between regulatory efficiency, providing the Companies with a reasonable opportunity to recover prudently incurred costs and allowing ratepayers the opportunity to realize the benefits of cost savings. The Panel also considered the materiality thresholds set by other jurisdictions, including Alberta and Ontario as well as CEC's proposed materiality threshold of 30 basis points of the Companies' ROEs.

The Panel agrees with Fortis' submission that CEC's proposed materiality threshold is too high and could impair the Companies' opportunity to earn a fair return. The Panel also agrees with Fortis that basing a materiality threshold on a dollar value would be simpler and more straightforward.

The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate. The Panel has used its best judgement to arrive at this quantum. It is an amount that is proportional to the relative size of the companies and is also a dollar value.

Using FEI's February 21, 2014 Evidentiary Update filed as Exhibit B-1-5 as a proxy, the materiality threshold for exogenous factors for FEI is approximately $1.15 million [2013 Base O&M of $229,489,000*0.5%]. Using FBC's Application filed as Exhibit B-1 as a proxy, the materiality threshold for FBC is approximately $300,000 [2013 Base O&M of $59,848,000*0.5%]. While the Panel acknowledges that exogenous factors could relate to either O&M or Capital, it considers using Base O&M as the foundation for calculating the dollar value threshold for each Company to be reasonable as the prescribed amounts are within the range identified by Fortis in the Oral Hearing and are reflective of the relative sizes of FEI and FBC.

The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.

The Commission Panel further directs that exogenous events not be aggregated. The materiality threshold must be applied to the costs/savings of each exogenous factor event and the costs/savings for a specific event must exceed the materiality threshold in order to be eligible for exogenous factor treatment.

The Panel notes that exogenous factors must be treated symmetrically to create a fair balance of risk between the utility and ratepayers. **Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is, any event resulting in savings must meet the criteria before it is accepted as an exogenous saving.**

<u>Process for Exogenous Factor Applications</u>

The Panel agrees with Fortis that it is not necessary to be overly prescriptive in terms of the timing of an exogenous factor application. The Panel recommends that to provide regulatory efficiency where possible, exogenous factor applications should be included as part of the Annual Review Process. However, Fortis may notify the Commission at other times during the year of exogenous events by letter to the Commission. The Commission Panel notes that consideration of exogenous events is not restricted to those raised by the Companies. Any party may make an application at any time in support of what it considers to be an exogenous event.

The Panel also agrees with Fortis that it is not practical to be overly prescriptive at this time as to the appropriate recovery mechanism for exogenous factor events. The Panel therefore accepts Fortis' proposal to address the appropriate recovery mechanism of exogenous amounts on a case-by-case basis. These recovery mechanisms could include, among other things, flow-throughs, deferral accounts, or true-ups. **The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.**

2.1.7 Flow-Through Items

Fortis proposes to flow-through various items which the Companies characterize as "known" or "foreseen" but not controllable. These flow-through items will be forecast each year during the Annual Review Process and thus not included within the PBR formula. For flow-through items which also have an accompanying deferral account, any variances between actual and forecast amounts will be added to the deferral account and amortized into rates outside of the formula. FEI already has a number of deferral accounts for these purposes; FBC is requesting establishment of certain deferral accounts for the same purpose. The issue of deferral accounts related to flow-through items is addressed in the next section. For flow-through items which do not have accompanying deferral accounts, Fortis proposes that the variances between forecast and actual amounts each year will be subject to the 50/50 Earnings Sharing Mechanism (ESM). (FEI Exhibit B-11, BCUC 1.21.4, 1.21.5; FBC Exhibit B-7, BCUC 1.37.4, 1.37.5) Please refer to Section 2.3.1 for further discussion of the ESM.

FEI proposes to classify the following items as flow-through:

- Interest Expense;
- Return on Equity;
- Taxes;
- Pension and Other Post-Employment Benefits (OPEB);

- Insurance Expense;
- Revenues;
- Depreciation and Amortization; and
- Rate Base other than Plant in Service (i.e. working capital, deferred charges).

(FEI Exhibit B-1, pp. 68–69)

FBC also proposes to classify the above items as flow-through, with the exception of non-Sales Revenue. FBC clarifies that it intends only to flow-through revenue from sales of electricity. (FBC Exhibit B-7, BCUC 1.37.4) However, in the Oral Hearing FBC further clarified that while the flow-through revenue is primarily electricity sales, there are other forms of tariff revenue included within the flow-through revenue category (T4:827, lines 9-14). Additionally, FBC proposes to flow through Power Purchase Expenses through the use of its Power Purchase Expense deferral account. (FBC Exhibit B-1, pp. 61–63; FBC Exhibit B-1-5, p. 1)

FEI described the ways in which it attempts to control each of the flow-through items to minimize the impact on customer rates, stating that for each of the proposed flow-through items there are "often components that are controllable and others that aren't." FEI further submitted that "[i]n most cases, it is the rate component of the expense that results in the item being deemed uncontrollable…" (Exhibit B-8, CEC 1.46.1)

In its response to CEC IRs 1.34 through 1.40, FBC described the variables which go into its determination of each flow-through item and also provided a discussion of the variables which are a function of company policy and practice and therefore may be somewhat controllable by the Company. (Exhibit B-10, CEC IRs 1.34 through 1.40)

Fortis submits that including uncontrollable costs within the PBR formula could result in windfall gains or losses to either the Companies or the ratepayers (Fortis PBR Final Argument, p. 42). Fortis also stated in the Oral Hearing: "…PBR is not about passing on uncontrollable costs between customers and companies, it's about incenting efficiencies and controllable costs." (T4:811)

<u>Insurance Expense</u>

FBC's Projected 2013 Insurance Expense is $1,588,000 and its 2014 Forecast Insurance Expense is $1,734,000 (FBC Exhibit B-1, Table B6-5, p. 53). While FBC proposes to treat the entire insurance expense as flow-through, it is proposing to capture only the variance between forecast and actual insurance premiums in the Insurance Variance Deferral Account. (FBC Exhibit B-1, p. 263)

FBC stated:

> "[i]nsurance premiums are driven by insurance market conditions which change continually and are affected by large global losses, due to catastrophic events such as earthquakes, hurricanes and forest fires, as well as through general market conditions related to the unpredictability of investment returns and loss history… This lack of controllability around insurance premiums is what has driven the request for an Insurance Variance Deferral Account as part of the 2014-2018 PBR Application." (FBC Exhibit B-7, BCUC 1.187.3)

FBC further stated:

> "[t]he primary reason FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account is to provide for consistent treatment between Electric and Gas divisions." (FBC Exhibit B-24, BCUC 2.58.5)

Of the total 2014 Forecast for Insurance Expense for FBC, Insurance Premiums make up approximately 84 percent with a forecast amount of $1,460,000. The remaining 16 percent is attributable to First and Third Party Liability Expense, which is forecasted to be $274,000 for 2014. An additional component of Insurance Expense is Asset Valuations, for the 2014 Forecast this amount is zero. FBC states that Asset Valuations are incurred every four years and therefore, this expense is only included in the 2017 Forecast. (FBC Exhibit B-24, BCUC 2.59.1)

FBC stated that it "would not object to changing the method of determining O&M Expense in order to exclude only insurance premiums from the I-X formula, providing the 2013 Base O&M Expense is revised to include the forecast $274 thousand of First and Third Party Liability Expense" (FBC Exhibit B-24, BCUC 2.59.1).

FBC provided the following breakdown of insurance expense for 2013 Projected and 2014 Forecast:

Table 2.18 FBC Insurance Expense

	2013	2014 Forecast	Variance
		($000s)	
Premiums	$1,422	$1,460	$38
Appraisal Fees	$60	-	$(60)
1st & 3rd Party Claims	$106	$274	$168
Total	$1,588	$1,734	$146

(Source: FBC Exhibit B-24, BCUC 2.59.2.1)

FEI's entire Insurance Expense is attributable to Insurance Premiums (Exhibit B2-24, Undertaking No. 8).

Intervener Submissions

CEC raises the following concerns in its Final Argument about Fortis' proposed flow-through items:

1. The substantial dollar amount of the flow through items and the resultant loss of oversight of significant expenditures;
2. The loss of incentive to control partially controllable expenditures;
3. The combination of the incentive to reduce costs related to achieving revenues while flowing through the revenues, resulting in the lost opportunity for ratepayers;
4. The ability for a utility to flow through costs that might otherwise be included in its formulaic spending resulting in undeserved earnings at ratepayer expense.

(CEC PBR Final Argument, p. 172)

CEC further highlights its concern that by virtue of entering into the PBR regime and thus moving from a cost of service revenue requirement application to an annual review process, the Commission will lose the following:

1. Most of the oversight on flow through items; and
2. Openness and transparency.

(CEC PBR Final Argument, p. 172)

CEC points out that the flow-through items represent approximately 80 percent of FEI's revenue requirement or 60 percent of the delivery margin revenues (CEC PBR Final Argument, p. 173; Exhibit B2-8, BCUC 3.51.3). For FBC, approximately 82 percent of the revenue requirement is determined outside of the PBR mechanism (FBC Exhibit B-7, BCUC 1.21.1). CEC submits that given the fact that the majority of the costs and revenues are outside of the PBR formula, the result is a "significant loss of openness and transparency that would otherwise be afforded under a Cost of Service review." (CEC PBR Final Argument, p. 173)

CEC states that it "does not accept that the Utility is essentially unable to influence the vast majority of its costs." It submits that "[a]ctivities such as managing interest expense and taxes are key customer concerns that are tracked outside but are not entirely outside management control and under PBR there is limited to no incentive to manage these costs, nor appropriate oversight in the Annual Review." (CEC PBR Final Argument, p. 175) CEC further submits that "partially controllable areas may be a good place to apply more innovation especially since the earlier PBRs have apparently resulted in all the 'low hanging fruit' being already picked" (CEC PBR Final Argument, p. 176).

CEC also states that "incremental revenues in FEI are derived through RNG [Renewable Natural Gas], NGT [Natural Gas Transportation], new markets and increases in throughput and customer additions among others." CEC submits that it is "unreasonable to expect that the Utility will expend significant additional resources seeking projects that will increase customer load for customer benefit because such efforts are likely to increase costs included in the formulaic spending envelope and as such would not be in the Utilities' best interest." (CEC PBR Final Argument, p. 178)

CEC notes in its Final Argument that the Companies would not object to excluding only the insurance premiums portion of insurance expense from the I-X formula; however, CEC does not indicate whether it recommends this treatment (CEC PBR Final Argument, p. 189).

With regard to Rate Base other than Plant in Service, CEC submits "there is no particular need to have these variances subject to ESM… these items should be handled in a similar manner with other flow through items where the actual costs and revenues are the basis for customer rates." (CEC PBR Final Argument, pp. 190–191)

BCPSO submits that it is reasonable that only the insurance premiums portion of insurance expense be excluded from the PBR formula; however, BCPSO disagrees with FBC's proposed calculation of the insurance expense to be added to the 2013 Base O&M (BCPSO FBC Non PBR Final Argument, p. 4).

Fortis Reply

Fortis submits that its proposed flow-through treatment actually maintains the existing risk profile for customers and the Companies, and it is consistent with how these items would be treated under a cost of service model. Fortis further submits that eliminating flow-through treatment of uncontrollable costs would actually shift risk to the Companies. (Fortis PBR Reply, p. 39)

Fortis states that the flow-through items will be reviewed each year under PBR at the Annual Review, which is twice as often as under a two-year cost of service revenue requirements application.

Fortis further submits: "It is perplexing that CEC seems unwilling to rely on FortisBC's willingness to propose revenue generating initiatives under PBR when it seems to trust FortisBC under COS [cost of service] and the incentives in each case are identical" (Fortis PBR Reply, p. 40).

Commission Determination

Fortis' proposed lists of flow-through items are substantial when compared to the Companies' overall revenue requirements. FEI's proposal for flow-through items is comparable to its previous PBR plan, though certain items such as Late Payment Charges have been re-classified from controllable to non-controllable which has resulted in additional items being removed from the

PBR formula in the current Application. Under FBC's previous PBR plan, fewer items were treated as flow-through in comparison to FBC's current PBR plan.

The Panel is concerned by the Companies' broad-sweeping approach to its treatment of flow-through items and believes that it is likely that certain components within the broader expense/revenue categories could be classified as partially controllable and therefore added back into the PBR formula. However, the Panel acknowledges that whether or not certain of the proposed costs/revenues are controllable, partially controllable, or non-controllable, it may not be appropriate to inflate these costs using the proposed I-X formula, and there is no evidence on the record which provides alternative formulaic methods to apply to these costs/revenues.

Additionally, while a substantial percentage of the Companies' revenue requirements are proposed to be classified as flow-through, the largest percentage relates to cost of gas for FEI and Power Purchase Expense for FBC, neither of which are appropriate for inclusion in the PBR formula. The Panel recognizes the importance of aligning the PBR plan with the X-Factor research. Since many of these flow-through items were not excluded from the X-Factor research, excluding them from the formula reduces the Companies' risk and therefore should be considered a benefit to them.

Based on the aforementioned considerations, the Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below. The Panel notes that this determination relates only to whether or not Fortis' proposed costs and revenues are approved to be treated as flow-through items. The subsequent section in this Decision (Section 2.2.5.1) addresses whether variances between forecast and actual flow-through costs/revenues are approved to be recorded in deferral accounts.

<u>Insurance Expense</u>

The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense. The remaining components of Insurance Expense must be added to the Companies' 2013 PBR O&M Bases. **The Panel directs the Companies to update the flow-**

through expenses in the Final Compliance Filings so that only Insurance Premiums are included in the Insurance Expense flow-through.

Flow-Through Items Subject to 50:50 Earning Sharing

The Panel agrees with CEC that it is not appropriate to apply the 50/50 ESM to flow-through items. Through responses to IRs, Fortis has identified the following flow-through items to which it proposes to apply the 50/50 ESM: FEI's Industrial delivery revenues, and FEI and FBC's rate base other than Plant in Service. However, this treatment was not specifically described in either Company's Application so the Panel is unclear as to whether there are other flow-through revenues and/or expenses currently proposed to receive this treatment. **The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that the ESM mechanism is not to be applied to flow-through items.**

Issues Raised by CEC

With respect to the issues raised by CEC regarding the Companies' lack of incentive to develop revenue-generating projects during the PBR term, the Panel accepts Fortis' proposal to bring forward revenue-generating items at the Annual Reviews. The Panel does not consider the incentives regarding revenue generation to be any more or less impactful under a PBR regime than they are under a cost of service regime.

The Panel acknowledges CEC's concerns regarding lack of oversight and openness/transparency over the flow-through costs/revenues and agrees that a robust and thorough Annual Review process is a critical element of the PBR plan. This issue is addressed in Section 2.3.6 of the Decision as part of Annual and Mid-Term Reviews.

2.1.7.1 Deferral Accounts for Flow-Through Items

FBC proposes to establish a number of deferral accounts that are designed to specifically address some of its proposed flow-through items. The requested deferral accounts are:

- Tax Variance deferral account, with amortization in the following year;
- Property Tax Variance deferral account, with an amortization period of 3 years;
- Insurance Expense deferral account, with amortization in the following year; and
- Interest Expense deferral account, with an amortization period of 3 years.

FEI has previously received Commission approval to utilize the four deferral accounts listed above. The amortization periods for FEI's deferral accounts are the same as the amortization periods requested by FBC. (FEI Exhibit B-1-1, Appendix F4)

FBC submits that the deferral accounts are required in order to avoid windfall gains and losses given the uncontrollable nature of the proposed flow-through items. Additionally, FBC submits that this reduces the "controversy" around forecasting during the Annual Review process as any variances will be captured in the deferral account. (T4: 830)

FBC states that by utilizing these deferral accounts, customers only pay for expenditures that are actually incurred. FBC also submits that establishment of these deferral accounts will be consistent with FBC's sister companies, such as FEI (FBC Non PBR Final Argument, pp. 78–80).

For the deferral accounts which are proposed to have a three year amortization period – the Interest Expense Variance deferral account and the Property Tax Variance deferral account – FBC submitted that three years is appropriate because it provides a reasonable balance between rate smoothing and ensuring that customers are paying for the true cost of service in a timely manner. Additionally, FBC noted that the requested amortization period is consistent with FEI's approved amortization period for the same deferral accounts. (FBC Exhibit B-7, BCUC 1.190.6)

Further submissions on the nature of the proposed deferral accounts were also canvassed by the Commission Panel during the Oral Hearing Phase conducted on July 14, 2014 (Exhibit A-44).

Intervener Submissions

BCPSO has no concerns with FBC's proposed approach to calculating forecast income and property taxes for 2014 (BCPSO Non PBR Argument, p. 14).

BCPSO points out that FBC's main rationale for the difference in recovery periods for the two tax-related deferral accounts appears be that the proposed recovery aligns with the recovery periods for comparable FEI deferral accounts. BCPSO submits that the amortization periods for refund/recovery should be more principled than just "that's how FEI does it." These principles should include considerations of: matching cost/benefits to the appropriate period as well as rate stability. BCPSO submits that a one-year refund/recovery period would appear appropriate unless there is a significant balance that is likely to create material rate instability. BCPSO does not elaborate on why one year is more appropriate. (BCPSO Non PBR Final Argument, p. 18)

In its Final Argument, CEC appears to support the deferral treatment for these proposed flow-through costs because they "can provide customers with reassurance that they will be paying the actual costs rather than forecast costs." CEC is of the opinion that the utilities have some control over income taxes, property taxes and interest expense but indicated that so long as they are being treated outside of the PBR formula, there will need to be a robust review of these expenses during the annual reviews. (CEC PBR Final Argument, pp. 187–189)

During the Oral Hearing Phase on July 14, 2014, the Panel posed the question: "are these deferral accounts necessary," and further "what other options are available?" (FBC Exhibit A-44, FEI Exhibit A-38) CEC and COPE submitted that they support FBC's proposal to establish these deferral accounts with the additional suggestion by CEC that tighter oversight is required. Most of the interveners observed that these deferral accounts were not in place during the last PBR and questioned the need for them at this time. The ICG suggested that another method would be to take the 2013 inflation adjusted actuals into the PBR formula and eliminate the need for deferral accounts. IRG supported the proposal by ICG. Several interveners suggested that these deferral accounts are a transfer of risk from the utility to the ratepayer. (T8:1421, 1433, 1439, 1446–1451, 1462)

Commission Determination

In the previous section of the Decision, the Panel has determined that Fortis' proposed flow-through items, with the exception of a portion of Insurance Expense, are approved to be treated as flow-throughs to the customer. Now, the secondary issue is how to deal with the variances between forecast and actual amounts which will arise each year.

The issue before the Panel is whether establishment of these deferral accounts are necessary in order to enable the flow-through of expenditures. This issue applies to both FEI and FBC although FEI did not explicitly apply for any new deferral accounts for flow-through items.

The Panel notes that these deferral accounts were non-existent during FBC's last PBR and therefore does not agree that they should now be considered *necessary* in order to flow through these costs to ratepayers. During the last PBR, any differences between actual and forecast expenditures of prior years were identified in the Annual Reviews and then flowed through to the calculated revenue requirement for the current year. For example, incremental interest costs above the previous year's forecast were flowed through to the customer before the ROE sharing mechanism was applied. This method still allows for the flow through of these types of expenditures *without* the use of deferral accounts, particularly in the case where a deferral account has an amortization period of only one year.

FBC has requested the establishment of a Tax Variance deferral account and an Insurance Expense Variance deferral account with proposed amortization periods of one year. Because these deferral accounts are not required to flow through expenses under the PBR plan and the amortization periods proposed are limited to one year, **the Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.**

With regard to the requested Property Tax Variance deferral account and the Interest Expense Variance deferral account, the Panel acknowledges that the situation is somewhat different due to the fact that FBC has proposed three-year amortization periods for these deferral accounts. While the Panel recognizes that rate smoothing is an important consideration when setting amortization periods for deferral accounts, it does not consider this to be a determinative factor in the case of these requested deferral accounts. The variances between forecast and actual/projected property tax and interest expense do not appear large enough to warrant a need to spread the amounts over multiple years. Therefore, the Panel applies the same reasoning for these requested deferral accounts as we did to the Tax Variance deferral account and the Insurance Expense Variance deferral account. The use of deferral accounts is not necessary to flow-through variances between forecast and actual expenses under PBR. **Accordingly, the Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.**

The Panel notes that the denial of these deferral accounts does not impact the determination that the actual expenditures of these items should be flowed-through to customers (see previous section in this Decision). In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FBC to true-up these costs each year**. Finally, the Panel also clarifies that these flow-through items should be applied first, and then a calculation of the earnings sharing mechanism will follow. This is the same treatment as conducted by FBC in its last PBR.

The Panel notes the distinction between FBC and FEI's current treatment of many of the flow-through items in that FEI has previously received approval for the deferral accounts requested by FBC in the Application.

However, the Panel refers to its determinations made above for FBC and re-iterates that these deferral accounts are not necessary to flow through costs to ratepayers. **Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax**

Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account.

For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.

In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FEI to true-up these costs each year**. Finally, the Panel also clarifies that these flow-through expenses should be applied first, and then a calculation of the earning sharing mechanism will follow. In other words, the same treatment as conducted by FBC in its last PBR should be followed.

2.1.8 Growth Term

2.1.8.1 O&M Growth Term

Both utilities include a term in their O&M formula to account for an increase in spending that they submit is required to account for net additional customers added to the system. The term is a ratio between the current year's expected average number of customers and the previous year's actual number of customers:

$$(AC_t/AC_{t-1})$$

where AC is the average number of customers that the utility serves in the year t or t-1. The effect of this term, all else equal, is to increase (or decrease, as the case may be) the previous year's O&M spending by that ratio. (FEI Exhibit B-1, p. 57; FBC Exhibit B-1, pp. 52–53)

Intervener Comments

BCPSO submits that "[w]hile growth in customers is a driver of costs, the history of costs does not support both an increase related to inflation and an increase related to growth" (BCPSO PBR Final Argument, p. 8).

Table 2.19 shows FBC's actual O&M per customer.

Table 2.19 FBC Actual Controllable O&M per Customer

	2008	2009	2010	2011	2012
Controllable O&M ($000)	39,860	40,113	39,649	41,411	40,087
Number of Customers	108,722	110,286	111,551	112,754	113,587
Actual O&M per Customer	$367	$364	$355	$367	$353

(Source: FBC Exhibit B-11, BCPSO 1.37.3)

For FBC, over the five years of actual results, the total O&M increases from $39,860,000 in 2008 to $40,087,000 in 2012, an increase of 0.14 percent in controllable O&M, compared to a 4.4 percent increase in customers over the same period. BCPSO's expert, Mr. Bell submits that history does not support the need for a growth factor for O&M for FBC because the actual O&M per customer remains fairly constant. (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

Table 2.20 FEI Actual Controllable O&M

	2010	2011	2012	2013
Number of Customers[8]	824,125	830,390	834,888	840,721
Actual O&M[9] ($ 000)	206,518	213,606	212,269	233,891
Actual O&M per customer[10]	$251	$257	$254	$278
Less Pension/OPEB/Insurance[11] ($ 000)	13,443	14,538	21,529	21,255
Total Controllable O&M ($ 000)	193,075	199,068	190,740	212,636
Controllable O&M per Customer	$234	$240	$228	$253

BCPSO states that for FEI, the 2012 cost per customer is $254, which is only 0.40 percent higher than the 2011 amount of $253 (In FEI Exhibit B-6, BCPSO 1.16.2, FEI provided $253 as the PBR tracked O&M per customer as opposed to the $257 as shown in Table 2.20 which is calculated from the information in the Panel IR). This increase is lower than the inflation increase for that period, and in its view, does not demonstrate a need for a growth factor. It states that "[p]roviding a growth component, in excess of the I-X would not provide an incentive to continue this pattern of constant cost per customer." (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

Fortis disagrees, stating "[t]he simple fact that the results are provided on a per customer basis means that customer growth is reflected implicitly in the calculations already" (FEI Exhibit B-44, pp. 3–4).

However, Mr. Bell explains that if there was a need to allow for both inflation and a growth component, "one would expect to see that the O&M per customer would be going up on a constant basis, and I didn't find that, and so that was how I reached the conclusion that to have an inflation factor as well as a growth factor would produce forecasts that are likely in excess of what is." (T6:1307)

8 Exhibit B-54 Fortis Panel IR Response, Attachment 2.1, which includes 2012 customer count adjustment of 14,892 extended back to 2009
9 Exhibit B-1-5, Evidentiary Update February 2014, Table C3-1
10 Calculated as Total PBR[10] Tracked O&M/Number of Customers
11 Exhibit B-54 Fortis Panel IR Response, Attachment 2.1

Table 2.21 FBC FTE Count for the Period 2010 to 2012

2010	2011	2012
537.66	527.63	542.13

(Source: FBC Exhibit B-11, BCPSO 1.71.2)

BCPSO also argues that even if O&M costs do increase with growth, costs aren't as highly correlated to growth as the proposed formula suggests. It cites FBC's FTE levels, shown in Table 2.21 and FBC's comment that "[t]he FTE levels for 2013 and for the remainder of the PBR Period are expected to be at a level similar to 2012 on a total company basis." From this, BCPSO concludes that: "[g]iven the fact that the history of O&M does not support a growth factor, and the fact that FBC itself does not foresee growth in staff, a growth factor is not needed." (FBC Exhibit B-11, BCPSO 1.71.2; FEI Exhibit C5-6, p. 13)

Fortis submits that "[a] valid analysis cannot be based on a simple review of historical results, as they are highly dependent on the time period chosen and the assumptions made." (FEI Exhibit B-44, p. 3)

During the Oral Hearing, Mr. Bell testified that he agreed that as a utility adds customers, it must add various facilities and resources to serve those customers. However, in his view, "[u]sually a utility does not add incremental resources for each new service," because the utility would not "require additional resources immediately to maintain those facilities." Mr. Bell also stated that "[a]s you add more and more, eventually you need to add more resources" and that "when you reach a threshold" there will be a cost associated with adding the requisite resources. Mr. Bell agreed that these incremental costs apply when either FEI or FBC add customers. (T1:1311–1312)

In Fortis' submission, there are two reasons why it is reasonable to use customers to account for growth in the context of O&M. "First, adding customers directly impacts O&M. Costs for billing and meter reading are directly correlated to customer count and will increase as customer count grows. Costs for transmission and distribution operations and maintenance are indirectly related to customer count and will incrementally increase as customer and customer capacity requirements grow." (FEI Final Argument, p. 33)

B&V submits it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because "it effectively adds an estimate of additional O&M expense associated with system growth to the plan's revenue adjustment." (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, p. 53)

In Fortis' view, changing the O&M formula by removing growth, as advocated by Mr. Bell, is tantamount to increasing the productivity improvement requirements imposed on the Companies. Further to this, Fortis believes the structure of the O&M formula should remain the same as it has been in the past so that the productivity improvement requirements are clearly set out in the X-Factor, and not disguised in some combination of the X-Factor and growth or other elements of the formulas. (FEI Exhibit B-44, pp. 3–4)

CEC states that "there is a solid rationale for having an explicit term for operating scale in an escalation formula" (FEI Exhibit C1-22 BCUC 2.5.1).

2.1.8.2 Capital Growth

Table 2.22 shows the growth terms Fortis proposes for its Capital Formulas.

Table 2.22 Capital Formula Growth Terms

	FEI	**FBC**
Growth capital	(SLA_t/SLA_{t-1})[12]	(AC_t/AC_{t-1})
Sustainment Capital	(AC_t/AC_{t-1}).	(AC_t/AC_{t-1})
Other Capital	(AC_t/AC_{t-1}).	(AC_t/AC_{t-1})

(Source: FEI Exhibit B-1, pp. 62-64; FBC Exhibit B-1, pp. 56-67)

[12] SLA = Service Line Additions

B&V states that:

> "[o]f the three categories of regular capital expenditures that FEI has included in its PBR formula, Growth Capital differs from Sustainment and Other capital in that it is primarily driven by customer additions. In particular, Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. FEI will re-forecast the level of service line additions for upcoming years (driven off of the gross customer additions) in the PBR Annual Reviews." (FEI, Exhibit B-1, p. 62)

With regard to FEI's sustainment and other capital, B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system. (FEI, Exhibit B-1, p. 63)

Concerning FBC, B&V states that:

> "in actual fact, growth, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system." (FBC Exhibit B-1, p. 56)

Table 2.23 shows FBC's historic capital spending for the years 2007 through 2012.

Table 2.23 FBC Total Non-CPCN Capital ($ thousands)

	2007	2008	2009	2010	2011	2012
Generation Capital	19,781	15,355	18,411	17,555	15,956	6,985
Transmission-Dst Capital	95,575	76,321	72,416	104,488	48,109	35,734
Other Capital	13,834	7,912	8,342	8,448	12,145	9,674
Total Capital	129,190	99,588	99,169	130,491	76,210	52,393

(Source: FBC Exhibit B-15, ICG 1.36.1)

Table 2.24 shows capital expenses per customer FBC.

Table 2.24 FBC Capital Spending per Customer ($)

	2007	2008	2009	2010	2011	2012
Customer Count	108,722	110,286	111,551	112,754	113,587	108,722
Generation Capital per cust.	$182	$139	$165	$156	$140	$64
Trns/Dst Capital per cust.	$879	$692	$649	$927	$424	$329
Other Capital per cust.	$127	$72	$75	$75	$107	$89
Total Capital per cust.	$1188	$903	$889	$1,157	$671	$482

(Source: FBC, Exhibit B-11, BCPSO 1.37.3)

Intervener Submissions

BCPSO states that there is no pattern of correlation between capital and customers and therefore submits that, "there is no demonstrated need for a growth factor for FBC capital" (FBC Exhibit C5-6, BCPSO Evidence, p. 14)

CEC submits that "there may be factors related to growth that increase costs but submits that they do not do so in a liner manner and that providing for both inflation and growth in a linear manner results in an unreasonable spending allowance." (CEC PBR Final Argument, p. 68)

Commission Determination

Should the PBR Formulas include a Growth Term?

Mr. Bell suggests that because O&M expenses per customer haven't risen as quickly as inflation, there is no need for the O&M revenue formula to account for growth. The Panel does not agree with this interpretation. It is not possible to draw this conclusion because the evidence is inconclusive. The Panel agrees with Fortis that a historical examination of per-customer spending doesn't provide any information concerning the link between customer growth and costs incurred to meet the growth.

It is possible for expenses to be decreasing, for example due to efficiencies, at the same time that they are increasing due to an increase in the number of customers. Similarly, efficiencies could potentially drive a reduction in FTEs at the same time that an increase in customers drive an increase in the number of FTEs required.

With regard to efficiency driven cost reductions, the Panel notes that previously, FBC was under a PBR regime and during this period the X-Factor was approximately 2 percent for 2007, 2 percent for 2008, 3 percent for 2009 and 1.5 percent for 2010 and 2011. Inflation ran at approximately 2 percent during that period. (FBC, Exhibit B-1-1, Appendix D 1, p. 25) Given that FBC underspent its formula spending envelope during the last PBR, it is not unreasonable to expect that actual O&M per customer increased at a rate near or less than that of inflation.

Considering the issue of the effect of growth on spending generally, the Panel notes that a utility that services one million customers incurs more spending – both O&M and capital – than does a utility that serves 100,000 people. Therefore, it is reasonable to conclude there are cost increases associated with growth. Further, BCPSO acknowledges that customer growth is a driver of costs. The Panel is persuaded that it is appropriate that a revenue cap formula, such as the one Fortis proposes, should account for growth. However, what is at issue is the correlation between the actual number of customers and spending and therefore, what the growth factor should be.

Is the Growth Factor Fortis proposes the Correct One?

With the exception of FEI's growth capital formula, all growth terms are based on the number of customers. FEI's Growth Term is based on the number of service line additions. The Growth Term Fortis proposes for all formulas, except growth capital for FEI, is linear with a scale factor of 1. That is, if the number of customers is doubled, the spending envelope is, all else equal, doubled; if the number of customers triple, the spending envelope is tripled; etc. This relationship is the same over any range of customer numbers. For FEI's growth capital formula the same relationship applies to the number of service line additions.

However, growth related expenses may not be correlated in the manner suggested by the formula. Both capital and O&M growth related expenditures may be somewhat lumpy, causing spending requirements to increase in a step-wise manner. In this regard the Panel agrees with Mr. Bell's observation that costs only increase when a threshold in growth is reached.

For example, over a sufficiently large range of customer additions, there is correlation between the number of customers and the number of service trucks needed – increase the number of customers and there will be an increase in the number of trucks required. However, increasing by one customer, or ten, or even one hundred may not trigger the need for an additional truck. It is only when a threshold of new customers is reached that the need for a new truck is triggered and both the capital and O&M expenses associated with that new truck are required.

CEC argues that while costs do increase with growth, they may not do so in a linear manner. The Panel agrees this may be the case, and considers two examples of where costs do not increase linearly. A non-linearity may arise because of economies of scale. A utility that serves a million people may not incur 10 times the O&M spending as does a utility that serves 100,000. As the number of customers increases, the scale factor decreases. Potentially, many different scale factors could apply as the number of customers increases or decreases. Similar scaling issues may also apply to FEI's proposed growth capital Growth Term.

The issue of correlation between costs and the number of customers is further underlined by FBC's comments in its Non-PBR Reply (pp. 11–18). In response to a suggestion by CEC that customer service related costs be reduced to reflect a reduced number of customers, FBC submitted that it is inappropriate because "the costs for that department do not decline commensurately." Although this statement was made by and about FBC, it applies equally to FEI.

If the growth term in the formula doesn't accurately reflect Fortis' actual growth related spending requirements, in the Panel's view, the Growth Term should be adjusted. The adjustment may be in the form of a calibration to the proposed growth term – i.e. $0.5*(AC_t/AC_{t-1})$ instead of $*(AC_t/AC_{t-1})$. Further, the calibration factor may be different for different levels of AC. However, there is no evidence of what, if any, calibration is required.

Of further concern to the Panel is that the Growth Term relies on Fortis' estimate of the average number of customers in the upcoming year. In the event of over estimation, the spending envelope will be larger than otherwise required, thereby resulting in an opportunity to over-collect. Although ratepayers and shareholders share, on a 50:50 basis, any over-collected amounts, this represents a transfer of wealth from the ratepayer to the shareholder. If estimates do not display any significant bias either upward or downward over time, this is not an issue. However, consistent overestimates of customer growth will result in an unjust transfer from the ratepayer to the shareholder.

In Fortis' proposed PBR mechanism, if there is an over estimate, there is never an opportunity for true-up. This is a similar to the potential for bias that we observed in the use of a forecast inflation term.

Given these issues, the Panel is not persuaded that the proposed Growth Term is appropriate. We consider that the Growth Term as proposed has the potential to provide a more generous spending envelope than is warranted. **Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the**

ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service line additions two years previous. The Panel recognizes that this introduces some lag into the formula calculation, but we consider it necessary in order to eliminate the potential of upward bias. This is the same approach we took in the case of the Inflation Factor. **Accordingly, the Commission Panel approved Growth Terms of 0.5 * (SLA_{t-1}/SLA_{t-2}) for FEI's growth capital and 0.5 * (AC_{t-1}/AC_{t-2}) for all other cases.**

If Fortis has evidence that a different growth term is more appropriate, it can bring forward that evidence at any time.

2.2 Key PBR Plan Components

2.2.1 Earnings Sharing Mechanism

An Earnings Sharing Mechanism (ESM) is a mechanism added to some PBRs to allow for the sharing of efficiency cost savings between the customer and the utility. ESMs are described as "regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and the benefits of the PBR plan." In addition, if symmetrical, they serve to soften the impact of unintended consequences such as excessive utility gains or losses within a PBR. FBC states that in regulatory literature there are two schools of thought regarding ESM usage. One school asserts that ESMs decrease the incentive power of the PBR plan and impose additional regulatory burden and cost. The other indicates that ESMs allow for improved cost tracking and mitigates concerns with excessive profits or losses and represents a fair approach to sharing the benefits of a PBR plan. (FBC Exhibit B-1, p. 64)

Fortis, citing support from B&V, has proposed that a symmetric ESM be made a component of the PBR Plan. The proposal is for an ESM based on the 2007 PBR which called for sharing on a 50:50 basis among customers and the utilities of earnings either above or below the allowed ROE in a given year. The plan is for the shared earnings to be projected during each Annual Review process but finalized after year-end when actual results are known. (FBC Exhibit B-1, pp. 64–65)

Intervener Submissions

CEC submits that the proposed plan has eliminated an opportunity for the customer to address concerns and adjust earnings accordingly and has also eliminated the no surprise clause and the line-by-line review process to determine levels of sharing. CEC considers that these changes represent a departure from customer interests. CEC also submits that the ESM does not limit customer risk as it does not limit the extent of utility financial earnings and serves to support a longer period between rebasing because the utility must share its earnings. This extended period has its downside for customers, one of which is the lack of transparency as there is no oversight over the five-year period. This extended period provides an additional three years with which to take advantage of additional earnings as compared to a standard two-year cost of service process. (CEC Final Argument, pp. 109–120)

None of the other Interveners had specific comments with regard to the ESM.

Fortis Reply

Fortis, in Reply, notes much of what CEC has to say relates to the PBR generally and are out of context. With respect to the ESM failing to limit the risk to the customer because it does not limit the earnings available to the utility, Fortis points out that the ESM serves to mitigate risk as there is equal sharing of both upside and downside results thereby creating balance. (Fortis PBR Reply, p. 45)

Commission Determination

The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers. In our view, the inclusion of an earnings sharing mechanism balances the interests of the customer and the utility. That is, to the extent that there are gains or losses relative to the approved ROE, the fact that they are shared on a 50:50 basis between the ratepayer and the utility is reasonable. The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the course of this PBR, generate efficiency savings resulting in earnings which allow them to exceed the approved ROE return. Fortis has proposed that these savings be shared. To deny the customer the opportunity of sharing these savings would not be in their interest. However, the Panel does acknowledge that in approving a symmetrical ESM we are, in effect, reducing the risk faced by Fortis on the downside and there is a potential negative rate impact in the event of unforeseen circumstances. However, given the historical performance of the Fortis utilities in achieving their approved ROE, we consider this downside risk to be limited.

The Commission Panel has considered the submissions of CEC with respect to the inclusion of an ESM. The points raised by CEC seem to be more concerned with the approval of a PBR and how it is designed than with the ESM itself. These include matters such as the elimination of the no surprise clause, the potential for earnings by simply not spending and the proposed term of the PBR relative to a more traditional cost of service agreement with a shorter time frame. While the Panel acknowledges that these matters are important, we agree with Fortis that with respect to having an ESM or not, CEC's arguments are out of context. To the extent possible, matters such as these will be dealt with in other parts of this Decision.

Given the apparent lack of trust between the parties in this proceeding and concerns with the potential to game the results, the Commission Panel considers the inclusion of an ESM to be a positive measure in that there is a sharing of gains or losses and does not favour either side. Additionally, the Panel notes that none of the parties have proposed its elimination. Given these factors, the Commission Panel considers an ESM mechanism to be appropriate at this time.

2.2.2 Efficiency Carry-Over Mechanism

An Efficiency Carry-Over Mechanism (ECM) is a plan component that allows the utility to receive benefits in periods following a PBR period for savings resulting from measures taken and costs incurred during the PBR period. Fortis describes the ECM as a means to incent the utility to pursue efficiency initiatives throughout the entire PBR period. It is justified on the basis that without it, the utility will have decreasing levels of motivation to initiate efficiency improvements as the PBR period moves forward. Fortis states this is because under a fixed-term PBR, the payback to a utility's investment in efficiency improvements is earned only on those savings up to the end of the PBR. Therefore, the utility is motivated to initiate changes resulting in savings early in the PBR period to maximize its payback or in some cases to put off such projects because there is insufficient time remaining in the PBR to earn a return even recover costs. Inclusion of an ECM allows the utility to initiate efficiency improvements later in the PBR period but continue to earn a share of the return into the period following the PBR. (FEI Exhibit B-1, pp. 72–73; FBC Exhibit B-1, pp. 65–68)

The Commission approved the use of an ECM in the 2004 PBR Plan for FEI. The ECM allowed accumulated capital carrying cost and depreciation benefits to continue at a rate of 2/3 in the first year and 1/3 in the second year following the end of the PBR. In the current Applications, Fortis is proposing an enhanced ECM for both FEI and FBC which includes two additional components; the inclusion of O&M savings in addition to capital and the use of a five-year rolling carry-over period for the sharing of savings following the year in which the improvement occurred, regardless of when the PBR period ends. Fortis states that including O&M savings in the ECM maintains a balance between capital and O&M savings initiatives, and that the inclusion of a five-year rolling carry-over period eliminates concerns with timing from decision-making and promotes ongoing efficiency improvement initiatives. (FEI Exhibit B-1, p. 74; FBC, Exhibit B-1, pp. 66–67)

Based on this, Fortis proposes implementing the five-year carry-over plan where the incremental O&M and capital savings are calculated as the sum of:

1. Variance of current year formula based O&M less cumulative O&M savings from prior years of the PBR Plan; and
2. Current year plant additions savings relative to current year allowed plant additions derived from PBR capital formula multiplied by a base rate factor of 12 percent (15 percent for FEI).

Fortis states that the 12 percent rate base factor represents the avoided revenue requirements from reduced capital expenditures. Avoided revenue requirements components include return on rate base, depreciation expense and associated taxes. The 50:50 sharing between ratepayer and shareholder will apply to the ECM in the same manner as it does within the PBR period.

Fortis states that the inclusion of an ECM has the support of B&V "because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity in the later years of the PBR Plan." This is possible because disincentives to install new productivity initiatives as the PBR Plan ends do not exist. (FEI Exhibit B-1, pp.74–75; FBC Exhibit B-1, pp. 67–68)

Intervener Submissions

CEC considers the proposed ECM to be detrimental to ratepayer interests and does not agree with the mechanism proposed by Fortis. CEC recommends the ECM as proposed by the utility be rejected outright. It submits that its issues with the proposed ECM mechanism are significant and that the theory and rationale behind the mechanism is incorrect and the benefit claims are "presumed rather than actual."

CEC considers the inclusion of O&M in the ECM represents additional ratepayer costs with no additional benefits. This "amplifies the underspending of an overly generous formula." CEC further states that in addition to the inclusion of O&M and a rolling carry-over mechanism, the current ECM proposal includes a full payment rather than a declining one, has a longer term and includes an increase of the rate base benefit factor (from14 percent to 15 percent for FEI). It submits that these changes are detrimental from a customer perspective and are not well supported in evidence.

CEC has numerous other issues with the proposed ECM mechanism. These include perverse incentives, basing rewards or benefits on a presumption that they last for at least 5 years and its inclusion eliminates benefits which would have been derived from rebasing. In CEC's view the key issue is the determination of the appropriate time for rebasing embedded savings and further submits that this could vary considerably based on the nature of the efficiency project and life of potential savings.

CEC accepts that there will be instances where there will be value in the utility having longer payback periods available. These may be warranted where the utility has made a significant investment in efficiency measures. However, in such instances deferral accounts could be used as a mechanism to manage such longer-term payback periods. These would not limit the payback to any term and would reduce risk for the utility and ratepayers in addition to ensuring that there will be greater Commission oversight. (CEC Final Argument, pp. 23, 125–130)

BCPSO notes that ECMs are not common in PBR plans, pointing out that Fortis was only able to identify two jurisdictions in Canada where they exist. BCPSO's concern with the use of ECMs in this instance is that Fortis is using the building block model where:

> "the utility can under spend on O&M and capital in each year and earn superior returns, and then claim an ECM. But there is no need, in circumstances where the utility can benefit from underspending the formula, to also provide an additional incentive to underspend in the form of an ECM." (BCPSO PBR Final Argument, p. 11)

BCPSO's overarching concern is best summarized in the following statement: "the issue is that the company can spend less O&M and Capital, and in effect double dip, gain during the PBR period by spending less, and then achieve superior returns after the end of the PBR for the same reductions." It submits that there is not a need for an ECM in this PBR. (BCPSO Final Argument, pp. 11–13)

BCPSO points out that Fortis' ESM is also a Loss Sharing Mechanism, in that it provides for a 50:50 sharing of earnings above and below the allowed ROE. In the event Fortis fails to earn its allowed return during the PBR period, the ESM requires ratepayer contribution above the formula derived costs during the PBR term, then additionally, the ECM requires ratepayer's shared contributions after the PBR term. (BCPSO PBR Final Argument, p. 14)

ICG does not support an ECM as it "does not believe that regulatory parameters affect efficiency initiatives in the manner suggested by FBC, at least sufficiently to justify the excess returns." ICG submits that an ECM must not be a windfall for the utility and the Panel needs to be certain that its inclusion will benefit customers. However, if approved, the efficiency gains have to be measured and must be allocated symmetrically. That is "if efficiency gains are achieved then the utility receives a higher return, but if efficiency losses are realized then the utility receives a lower return." (ICG Final Argument, pp. 23–25)

ICG considers the utility to be responsible for achieving and then measuring efficiency savings. It provides a hypothetical example where the utility spends $1 million on an efficiency initiative to achieve a $500,000 efficiency saving. If the savings are than expected results then the utility, not the customer, pays the difference between the cost of the efficiency measure and actual savings. It appears that ICG is recommending that the 50:50 sharing mechanism which has been proposed by Fortis and approved by the Panel be suspended for the ECM applied beyond the end of the PBR period. In this way, the utility would receive the credit for any gains and also bear any losses related to an approved ECM in the period following the PBR. (ICG Final Argument, pp. 23–25)

Fortis Reply

Fortis, in Reply, views the position taken by CEC as to the "the customer continu[ing] to reward the utility when there are no earnings which it is 'sharing with the customer'" as "starting from the wrong premise." It reiterates that the inclusion of an ECM is designed to make the company whole for the costs not yet recovered in rates prior to the end of the PBR. In addition, it takes issue with CEC's suggestion that the lack of research and documentation is the reason the ECM should be rejected pointing out that the concept is familiar in that ECMs have been used in previous PBRs and are currently in place in Alberta and Quebec. Fortis also notes that Dr. Lowry's comments on ECMs were largely supportive of including this component.

Fortis had no additional comments regarding CEC's concerns with respect to term length of the current ECM proposed and the move away from a declining payment schedule which had characterized earlier iterations.

Fortis also withheld comment on CEC's contention that the time for rebasing savings is not always five years and varies by the nature of the efficiency project and the length of potential savings. The Commission Panel notes that Fortis had previously addressed CEC's suggestion that as an alternative deferral accounts could be used as a mechanism to manage longer payback periods. In response to CEC FEI 3a.38.5 Fortis states: “FEI believes that a deferral account approach would involve more regulatory process and would run counter to the objectives under PBR of streamlining the regulatory process and aligning the interests of customers with the interests of the utility.” Fortis further states that such an approach may be possible and could be applied to larger scale initiatives but it would be less practical to employ this with smaller scale programs. (Fortis Reply, pp. 49–52; FEI Exhibit B2-2, CEC 3a.38.5)

Fortis states in response to BCPSO’s comments that the underlying premise of its argument “is that the Commission is incapable of doing its job” and the inclusion of an ECM represents a significant downside for the customer. In Fortis’ view, the Commission should be reviewing this Application on the basis that it will be able to determine just and reasonable rates when next there is a COS Application. (Fortis PBR Reply, pp. 47–49)

Fortis makes no reply to the ICG submissions.

Commission Determination

The Commission Panel cannot help but acknowledge the level of cynicism and distrust implicit in the submissions of the interveners with respect to the inclusion of an ECM in the Fortis PBR. It is clear from these submissions that the interveners view the proposed ECM as being one-sided and very much in favour of the utility. BCPSO is perhaps most emphatic when it states that in spite of under spending on both O&M and capital in each year and earning what might be described as superior returns, Fortis then gets to claim their part of the ECM in the period subsequent to the PBR period. Concerning BCPSO’s comments, Fortis’ interpretation is that it is based on the underlying premise that “the Commission is incapable of doing its job” and in its view the Commission should consider this Application from the perspective that it will be able to determine just and reasonable rates in the next COS Application. The Commission Panel agrees. Our review of this Application should lead to determinations that, to the best degree possible, we can anticipate and control the ability of the utility to “game” any element of the PBR and minimize opportunities for Fortis to benefit at the expense of the ratepayer.

In the view of the Commission Panel, the ECM proposal put forward by Fortis favours the utility and puts the ratepayer at risk for future payments following the PBR period with no assurance that the savings will carry forward. Specific concerns of the Panel include:

Five-Year Rolling Carry-Over Period

As structured, the ECM is based on the assumption that any savings which occur warrant a payback period (which is shared between the ratepayer and the utility) of five years. There has been no compelling evidence to suggest that five years is an appropriate time period for all or any efficiency initiatives. The Panel notes that ECMs do not appear to be commonplace and, where they exist, no evidence has been presented to suggest they have a five-year payback period. There are variations of ECMs in both Alberta and Gaz Metro but neither of these extend for a five year period. (T2:305)

The Use of a Formula Driven O&M ECM Calculation

The ECM, as proposed, rewards additional O&M savings in later years of the PBR by carrying the reward for them over to the post PBR period. This, in the view of Fortis, provides an incentive to continue to develop efficiency measures in later years of the PBR. The Panel acknowledges there is some logic to this but also notes that there has been no attempt in the proposal to separate those savings that are related to an actual initiative from those that result from simply not spending the funds or being unable to do so due to circumstances unforeseen by Fortis. In either case, the savings would apply and carry over (albeit shared with ratepayers) into the post PBR period. Even if identified during the rebasing process, there would be instances where the Commission would have no option but to approve the inclusion of these savings as justified new expenses in future revenue requirements while, at the same time, allowing the savings for them to carry forward into the post PBR period. The Commission Panel considers the risk associated with this to be considerable. Moreover, while incenting the development of efficiency initiatives later in the PBR period, the Fortis proposal equally incents under-spending or gaming the formula.

The Use of a Formula Driven Capital ECM Calculation

Many of the concerns raised with respect to the O&M ECM formula also apply to capital. Delay of projects, whether through circumstances beyond the utility's control or by design are a commonplace occurrence. To apply a formula without consideration of the individual circumstances would leave it open for unintended consequences and potentially a windfall for the utility.

Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology. However, the Panel acknowledges that there will be instances where there are efficiency related programs with associated costs which may remain unimplemented if an ECM did not exist. Therefore, in spite of the concerns raised, we are persuaded that there is value in the inclusion of some form of ECM mechanism as a means of incenting the development of efficiency initiatives throughout the PBR period. However, the ECM mechanism must be transparent, flexible and allow a decision to be made on each initiative based on its individual circumstances taking into account the benefits, the period of the benefits, costs and likelihood for success. In addition, there is a need to track these investments and determine whether they deliver on the promised benefits. Creating a formal process to deal with ECM initiatives will provide greater transparency and hopefully reduce the distrust and cynicism referred to earlier.

Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative;

1. **ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year.**
2. **For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid.**
3. **Parties will have the opportunity to comment on the proposal.**

If agreed to by the parties, the proposal will go to the Commission with a recommendation for approval. If not agreed to, the proposal will go to the Commission for a Decision or development of further process. Based on these submissions, the Commission will make a determination as to the justification of each ECM proposal on a case-by-case basis.

2.2.3 Managing Service Quality

2.2.3.1 Purpose of SQIs

One of the more contentious issues with the Fortis PBR proposal is determining the role that SQIs play within a PBR Mechanism. SQIs have been recognized as an effective way to measure the performance of a utility from a variety of perspectives. These may include but are not limited to safety, customer service and service availability. As noted by FEI in its Application, SQIs "are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality" (FEI Exhibit B-1, p. 77). This raises the question that if service quality has been compromised in the interests of cost savings or efficiencies or simply suffers with no linkage to a particular act, what should be the consequences?

The Fortis proposal envisions that each year during the Annual Review, it will present the FEI and FBC projected results for SQIs to the parties and the related discussion will serve to provide an understanding of issues affecting the Companies' ability to meet established benchmarks. Fortis has further clarified this issue by stating that unsatisfactory performance as measured by non-financial SQIs are more appropriately assessed at the mid-term review allowing for measurement over a longer time horizon. (Exhibit B-1-1, Appendix D7, p. 17; Exhibit B2-8, BCUC 3.25.1) Thus, it seems that while SQIs will be a matter for discussion at the Annual Review, Fortis views the Mid-Term Review as the appropriate time to determine whether a serious problem or degradation of service exists.

Fortis has outlined no specific process for dealing with a degradation of SQI results. It takes the position that if there has been a serious unaddressed degradation in results that remains unaddressed, the Commission can explore potential off-ramps. Fortis describes the "off-ramp provision" as contemplating a complete regulatory review of the PBR Plan. This would be triggered only if there was "sustained serious degradation of the SQIs." (Exhibit B2-8, BCUC 3.25.2) This is in contrast to previous PBRs where the SQIs were reviewed annually and interveners had some level of input as to the level of earnings share if SQI benchmarks were not met.

Fortis' position on penalties or rewards is that given Fortis' lack of control, they should not be linked to SQI performance relative to their benchmarks. As an example, Fortis notes that "colder than normal weather coupled with higher gas costs can increase call centre volume dramatically and result in a one-time reduction in SQI beyond the reasonable control of the Company." In such instances, it should not necessarily be rewarded or penalized. Fortis acknowledges that one of the themes throughout the proceeding is that the Commission should be concerned that Fortis' SQI proposal lacks enforceable consequences. It points to its ongoing history with the management of SQIs as support for its current proposal. It also states that its witnesses have consistently voiced their commitment to managing the business in a manner that maintains existing service levels. (Fortis PBR Final Argument, pp. 151–152; Exhibit B2-11 CEC 3.40.1; Exhibit B2-8, BCUC 3.25.3)

Intervener Submissions

CEC submits that in the event of performance failures without adequate explanations, it is appropriate to enforce consequences. It also notes the lack of a definition for a serious service degradation and cites the AUC Decision[13] which developed a consultation process as a means of setting performance measures within PBR. CEC sees this as "an appropriate method of ensuring that the most important performance metrics are established and included as criteria for incentive payments." CEC believes the Fortis proposal leaves too much ground between the degradation of service and the move toward off-ramps. If service is degraded, the Commission is placed in the position of either accepting the results of degraded service or having to reconsider the entire regulatory process. CEC recommends that where targets are missed, the utility be subject to Commission examination during the Annual Review with a determination of appropriate consequences. (CEC PBR Final Argument, pp. 210–212)

[13] Included as Exhibit B-1-1, Appendix D8, pp. 91, 881–883

ICG considers the purpose of SQIs is to ensure the utility does not sacrifice service quality during a PBR. However, its position is that SQIs are "not sufficiently sensitive, with too many confounding factors, for service quality indicators to detect any changes to either O&M activities or capital investments during a PBR Plan." ICG argues that while reliability indicators like System Average Interruption Duration Index (SAIDI) or System Average Interruption Frequency Index (SAIFI) can change over time if maintenance activities or investments in infrastructure change, year-to-year changes are more affected by weather than any other factor. Consequently, ICG does not consider the professed purpose of SQIs to be achievable. (ICG Final Argument, pp. 35–36)

BCPSO notes that in the previous PBR, SQI results were reviewed annually and participants were able to make submissions with regard to whether a deviation from a benchmark was sufficient to warrant a limiting of incentive payments to the utility. Its view is that this approach should be taken in the current PBR plan as it falls short of cancelling the PBR in its entirety yet recognizes that customers suffer from a drop in service quality and should be compensated. (BCPSO PBR Final Argument, para. 64)

COPE states that at the "heart of the problem with the Companies' Service Quality Indicators proposal is that the way it approaches the *service* side of the [regulatory] compact is not consistent with its approach to the financial *performance and reward* side. It adopts a mechanism of financial risks and rewards to boost the financial performance of the utilities, but rejects that approach to service performance." (COPE Final Argument, p. 6)

COPE's expert witness, Ms. Alexander provides substantial commentary on the application of penalties for sub-standard performance on SQI's and recommends a program be put in place. These are also referred to as "compensation credits" designed to compensate the customer who has suffered the poor service quality (T5:875). Ms. Alexander was able to provide numerous examples in other jurisdictions where such penalty schemes are in place. (FEI Exhibit C2-13, BCUC 1.14.2)

In Final Argument, COPE muses that the use of the word "penalty" was unfortunate in that it was not an accurate reflection of Ms. Alexander's concept, which was compensatory in nature and not really punitive. In spite of extolling the virtues of the approach recommended by its witness, COPE stops short of specifically advocating that the Commission consider implementation of a penalty based regimen. In its conclusions COPE states that it agrees emphatically with the Fortis statement made in Final Argument:

> "In the event that the Commission considers the proposed PBR Plan and the existing statutory mechanisms to be insufficient, and considers it necessary to incorporate a term into the PBR Plan that makes earnings sharing conditional upon maintaining service quality, the Commission should proceed with caution to ensure that the PBR Plan remains compliant with the UCA and fair to the Company as well as rate payers" (FEI PBR Final Argument, p. 161)

COPE's concern is that the PBR is slanted toward the utilities and a reinforcement of the customer service side of the regulatory compact is needed. It views the SQI component of the PBR proposal as seriously deficient and asserts there is a need for mechanisms to ensure sufficiently robust service standards that will inhibit any incentive the utility may have to cut corners. To this end COPE states that "SQI's must be meaningful, they must be measurable, and they must have teeth" recommending the Commission develop an effective mechanism to rebalance PBR incentives to achieve this. (COPE Final Argument, pp. 46–50)

IRG does not support Ms. Alexander's penalty recommendations and recommends the Commission reject them. In IRG's view, the avoidance of penalties would become a distraction for FBC management and staff and not result in any material increases in service quality, reliability or safety. (IRG Final Argument, p. 12)

Fortis Reply

Fortis acknowledges that using Off-Ramps as an enforcement tool for SQIs is a blunt instrument. The Companies see it as a tool of last resort, stating that they have proposed the same service quality trigger that existed in previous PBRs. Related to this, Fortis does not define sustained serious service degradation considering it best to allow the Commission to consider all of the circumstances before a decision is made to terminate the PBR. (Fortis PBR Final Argument, pp. 88–89)

In considering the proposal to limit PBR incentives as a means of enforcing service quality, Fortis makes the following submission:

> "Under section 59 of the UCA, a rate is 'unjust' or 'unreasonable' if the rate is either '(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility' or (b) insufficient to yield a fair return. The rates under PBR are set based on the utility taking appropriate steps to deliver a particular level of service quality. The rate yielded by the PBR Plan is, in effect, too high if service quality declines materially as a result of some imprudent conduct by the utility. A finding of imprudence is a precondition to disallowing a portion of the incentive because the overall PBR must still confer an opportunity to earn a fair return. The presumption of prudence would apply." (Fortis PBR Reply, p. 90)

Commission Determination

There does not appear to be consensus among the interveners with respect to the Fortis SQI proposal. CEC, BCPSO and COPE are all in agreement that the Fortis proposal for the handling of SQIs falls well short of optimum and, to be effective, has to include consequences for serious degradation of service. For ICG and IRG the primary concern appears to be access to reliable service and neither supports the introduction of a penalty regimen as a means of achieving this. ICG has also raised concerns as to the effect of confounding factors such as weather on key reliability measures or whether established measures are effective at measuring the impact of changes in maintenance and infrastructure over shorter PBR time periods.

The Commission Panel is in general agreement with CEC, BCPSO and COPE with respect to the need for consequences related to service degradation. The Fortis proposal for the management of SQIs within PBR is much too vague and lacks consequences other than the potential for an off-ramp. The PBR is being approved with incentives for the utility to create efficiencies and reduce unnecessary cost. However, if O&M and maintenance capital are too tightly constrained this may result in a degradation of key service level areas. Therefore, the Panel considers that incentives related to reducing costs and creating efficiencies need to be counter balanced to ensure this occurs without a degradation of service levels as measured by SQIs. Confounding this somewhat is the point raised by ICG that the short-term actions taken by the utility affect long-term SQI results but may have limited effect on short-term measurements for some SQIs. On the other hand, external factors such as weather may have a significant impact on short-term SQI measurements which dissipate when considered over the longer term. Fortis has acknowledged this latter point by recommending that an assessment of unsatisfactory performance on SQIs should not occur until the mid-term review following year three of PBR. The Panel notes there is no evidence on the record concerning the length of time it takes for an action undertaken by a utility to be reflected in SQI performance. In the Panel's view a drop in performance on a SQI would likely depend on the particular performance measure and the severity of the action or inaction of the utility. Therefore, the Commission Panel is not persuaded there is justification for SQI review to be delayed beyond the next Annual Review.

Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. The Panel considers that a failure to underline the importance of SQIs sends the wrong message to the utility and invites behaviours which may not support the achievement of safe and reliable service.

The next question is "what consequences are most appropriate?" The ultimate consequence as proposed by Fortis is to invoke the off-ramp option and cancel the PBR. In the view of the Panel this should remain but in addition there is a need for less drastic alternatives to terminating the PBR. Ms. Alexander has proposed that the Commission institute a penalty regimen with predefined penalties (also referred to as compensation credits) assessed to the utility for failure to meet one or more SQI targets. This option received little support from the intervener group. Another option is to tie the achievement of the full earnings-sharing ratio conditional upon maintaining service quality levels. This approach, which was recommended by BCPSO, addresses a number of the concerns of interveners and creates consequences for failure to achieve satisfactory levels of service quality without going to a penalty based regimen as proposed by Ms. Alexander. This modified approach offers the advantage of linking consequences only to incentive earnings which exceed the Commission approved I-X formula driven ROE returns. Reducing excess earnings to no lower than the approved ROE is not unjust or unreasonable. In addition, because the maintenance of service quality is tied to the earnings sharing mechanism, it will only apply when there are incentive earnings to share. This clearly establishes the achievement of service quality standards as a precondition to the earning of incentives. As a consequence, concern that a utility may be motivated to put the achievement of service standards at risk in order to earn an incentive is, to a degree, mitigated. **Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.**

2.2.3.2 What SQIs are Appropriate?

The issues related to which SQIs are appropriate for this PBR received extensive review within the proceeding. Fortis has proposed a set of SQIs it considers appropriate for the purposes of the PBR. It has also provided a proposal for discontinuing some of the SQIs currently in place. The Fortis proposal and related issues raised by interveners will now be discussed.

<u>Fortis' Proposed SQIs</u>

Table 2.25 outlines the SQIs FEI and FBC have proposed. Fortis has proposed a benchmark as a measure of service quality for many of these.

Table 2.25 Service Quality Indicators (SQIs) Proposed by FEI and FBC

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Emergency response time	Percent of calls responded to within one hour	95%	Percent of calls responded to within two hours	85%
First contact resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone service factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	--	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries	--
Customer satisfaction index	Informational indicator	--	Informational indicator	--
Public contact with pipelines	Informational Indicator – 3 year rolling average of number of line damages per 1,000 BC One calls received	--	N/A	N/A
System Average Interruption Duration Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIDI (average cumulative customer outage time)	--
System Average Interruption Frequency Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIFI (average customer outages)	--

(Source: FBC Exhibit B-1, p. 69; FEI Exhibit B-1, p. 76)

Discontinued SQIs Proposed by Fortis

As previously noted, Fortis has also proposed to discontinue a number of existing SQIs which they believe are of little value going forward. These include the following:

FEI Discontinued SQIs Proposal

- Transmission Reportable Incidents
- Leaks per Km of Distribution System Mains
- Number of Third Party Distribution System Incidents
- Accuracy of Transportation Meter Measurement First Report
- Number of Customer Complaints to the BCUC
- Percent of Industrial Customer Bills Accurate
- Number of Prior Period Adjustments

(FEI Exhibit B-1-1, Appendix D7, pp. 16–17)

FBC Discontinued SQI Proposal

- Generator Forced Outage Rate
- Residential Connections Completion Time
- Residential Extension Quoting Time
- Residential Extensions Completion Time
- Injury Severity Rate
- Vehicle Incident Rate

(FBC Exhibit B-1-1, Appendix D6, pp. 12, 13)

Intervener Submissions

More generally, CEC takes the position that the SQIs put forward by Fortis do not adequately protect the ratepayer. An example of this is the lack of asset health SQIs which may incent the delay of maintenance activities resulting in undesired consequences. It considers many of the proposed SQIs to be of greater interest to residential customers than to commercial customers noting that FEI has no insight into commercial sector satisfaction given the cancellation of the Large Commercial Customer Satisfaction Survey. (CEC PBR Final Argument, pp. 194–196; pp. 203–204)

In assessing SQIs, CEC recommends the Commission consider measures that:

- Provide long-term protection to all ratepayer groups from service degradation or increased expenses;
- Deter cost–cutting in areas that can or could affect service quality and reliability;
- Adequately address all areas of service, especially those that may be likely targets for cost-cutting; and
- Are measurable/quantifiable.

(CEC PBR Final Argument, p. 193)

COPE considers Ms. Alexander's approach to calibration of benchmarks to be reasonable and balanced and urges the Commission to adopt best practices and not rely "on the lowest common denominator in establishing its policies for SQI in the context of a PBR." COPE supports the notion of relying on 3 year averages as a means of controlling service volatility. (COPE PBR Final Argument, pp. 27–30)

Interveners have made the following recommendations with respect to specific SQIs proposed by the Companies in their applications:

(i) Emergency Response Time

FEI proposes to change to the Canadian Gas Association (CGA) definition of an emergency event and the CGA response time calculation. Based on the CGA definition, FEI has, over the 2010 to 2012 period, responded to emergency calls within one hour 97.7 percent of the time. FEI proposes to set its emergency response benchmark at 95 percent stating that it is approximately equal to the industry average and in the top quartile of CGA members. (FBC Application, Exhibit B-1-1, Appendix D7, pp. 5–6)

CEC and BCPSO recommend that FEI should be required to maintain its emergency response time metric at current levels (97.4 percent) which it has been able to achieve on a consistent basis, rather than setting it at a lower level (95 percent). (CEC PBR Final Argument, p. 215; BCPSO PBR Final Argument, p. 19)

Over the same period FBC has responded to an initial identification of a loss of power, to arrival of FBC staff at the trouble site within two hours or less, 93 percent of the time. FBC states that its current benchmark is 85 percent and represents a level of response expected by its customers. It proposes to maintain the benchmark at this level.

BCPSO submits that the FBC emergency services benchmark should be set at least 90 percent as since 2007 FBC has achieved a level of 91 percent or higher and this is the level that customers have been receiving and has been sustained at current expenditure levels. (BCPSO PBR Final Argument, p. 16)

(ii) Meter Exchange Appointment

CEC and BCPSO agree with FEI's proposed 95 percent benchmark. CEC does not support the COPE proposal to replace this metric with a missed appointment customer credit of $25. (CEC PBR Final Argument, pp. 215, 216; BCPSO PBR Final Argument, p. 19)

(iii) First Contact Resolution

CEC considers first contact resolution as important to customers, but its usefulness complements other measures (CEC PBR Final Argument, p. 217).

(iv) Telephone Service Factor (emergency)

CEC and BCPSO agree with the proposed benchmark that 95 percent of calls be answered within 30 seconds or less (CEC PBR Final Argument PBR, p. 216; BCPSO PBR Final Argument, p. 19).

(v) Telephone Service Factor (Non-emergency*)*

CEC submits that the average wait time is not necessarily indicative of the wait time experienced by some customers. CEC recommends the Companies develop an abandonment rate measure and SQI. (CEC PBR Final Argument, pp. 216–217)

Ms. Alexander recommends 80 percent for both FEI and FBC referring to this as the best practice standard. (FEI Exhibit C2-10, p.27) BCPSO had no objection to the proposed Telephone Service metric (BCPSO PBR Final Argument, p. 19).

(vi) Billing Index and Meter Reading Accuracy

Ms. Alexander recommends that both of these indexes be eliminated for FBC as modern computerized billing systems make billing and meter reading highly accurate and timely. However, the metric should be retained for the gas utility. (FEI Exhibit C2-10, pp.28–31)

CEC disagrees with COPE pointing out the measure allows for the identification of problems. (CEC PBR Final Argument, p. 217)

Fortis Discontinued or Informational Only SQIs

Both CEC and COPE have concerns that the Companies have removed any SQIs with benchmarks or targets that are related to reliability. CEC notes that establishing SQIs intended to reflect the experience between the customer and the company are inadequate protection of customer interests pointing out that the interests of ratepayers go far beyond the typical 'customer experience'. CEC list customer interests such as asset health, corporate responsibility, special irrigation concerns or energy efficiency activities as examples of customer interests which are not covered by SQIs. (CEC PBR Final Argument, p. 202) Specific issues related to dropped or Informational Only SQIs are as follows:

(i) SAIDI and SAIFI

FBC proposes to report on the SAIDI and SAIFI service quality indicators on an informational basis only. Fortis suggests that these indicators are not considered to have a significant linkage between costs and results and it may take years for the results to be evident.

CEC believes that whether an indicator responds immediately or not to cost cutting should not exclude its use. In CEC's view, the ratepayer needs protection from long-term degradation in reliability which in its view stems from asset health which can be affected by the level of expenditures on maintenance. (CEC PBR Final Argument PBR, p. 203–205)

COPE submits that FBC's generally acceptable performance for reliability as exhibited by SAIFI and SAIDI would be placed at risk during the PBR period by relegating it to an informational SQI with no performance target. (COPE Final Argument, p. 18)

(ii) All Injury Frequency Rate (AIFR*)*

Both FEI and FBC propose the use of the AIFR as an informational SQI. COPE argues that the Companies should be held accountable for AIFR results. While recognizing that the Companies cannot control the conduct of all their employees at all times, its expert witness, Ms. Alexander notes "management is in charge of the workplace culture, the safety systems, and the educational activities designed to prevent as many workplace accidents as possible." (COPE Final Argument, p. 40)

(iii) Public Contact with Pipelines

FEI has introduced the public contact with pipelines SQI to reflect the importance of educating the public on the risk associated with pipeline contact. The SQI is a "measure of the overall effectiveness of the public's awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers." FEI proposes that this SQI be an informational measure with no benchmark. (FEI Application, Exhibit B-1-1, Appendix D7, pp. 12, 13)

COPE argues that this is an important measure related directly to public safety and FEI should conduct itself in a way which mitigates risks and be held accountable for the results (COPE Final Argument, p. 38).

<u>Fortis Reply</u>

Fortis considers it appropriate that it has relied on a suite of SQI's that focus on the direct customer experience noting that the interveners seek to include additional performance indicators concerning a variety of matters including asset health and corporate responsibility. Fortis acknowledges that these matters may be of interest to customers but argues that it does not necessarily follow that SQIs related to these matters should be covered under the PBR plan. In support of its approach, Fortis notes that the Companies do not have the discretion to allow assets to deteriorate and they already report to the Commission in considerable detail in a more useful format (citing comments from T6:1196 with reference to metrics on the state of the assets and the reporting regimen through the Oil and Gas Commission).

Fortis argues that its current level of service is high and

> "[i]ncreasing service level requirements above the benchmarks proposed by FortisBC will give rise to asymmetric risk in circumstances where there is no direct correlation between utility spending and service levels." In other words, the odds are higher of missing a high benchmark metric as compared to a lower one unless it can be determined that additional expenditures can produce the desired results. It explains that it has set a reduced benchmark of 95 percent in the case of Emergency Response times because "the odds of falling below the benchmark of 97.6% for reasons beyond utility control are significantly higher than would be the case with a benchmark set at 95%." (Fortis PBR Reply, p. 84)

Commission Determination

There are two key issues that the Commission Panel must address. The first of these is concerned with whether the SQI's proposed by Fortis are appropriate. If not, what SQIs should be added? Related to this is whether the informational indicators as proposed, should be so categorized or whether some of these should be upgraded to full SQIs with performance benchmarks. The second issue deals with the level of the performance benchmarks.

<u>Are Fortis' Proposed SQIs Appropriate?</u>

Under the *Utilities Commission Act* the Commission has an obligation to ensure the utility is supplying "reasonable, safe, adequate and fair service" (s. 25). Reasonable, safe and adequate service entails providing services that are reliable, responsive to consumer needs and protective of the safety of the public which includes both ratepayers and employees of the Utilities. The Commission Panel considers Fortis' contention that SQIs should be focused on the customer experience as being too narrow in scope. In our view, the SQIs are a mechanism to assist the Commission to ascertain whether the Companies are living up to the obligations envisaged in the regulatory compact and legislated under the UCA.

The proposed benchmarked SQIs are focused primarily on the areas of direct interaction between the Companies and customers and don't fully reflect all of its service obligations. **Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.** All of these are required to enable the Commission to evaluate whether the Companies are meeting obligations under the UCA.

The Commission Panel notes that only two of the benchmarked SQIs proposed by FEI relate to safety (Emergency Response Time and Telephone Response – Emergency) and only one FBC SQI is safety related (Emergency Response Time). The remaining benchmarked SQIs, five in the case of FEI and four for FBC relate to customer/company interactions. Further, FEI has no service quality indicators dealing with reliability of service while FBC has only two, SAIFI and SAIDI, both of which are proposed as informational indicators. In our view, this does not reflect a balanced approach.

A concern has been raised by many interveners with respect to the elimination or a move to informational status of reliability related SQIs. Given the length of term of the PBR, the Panel agrees and is equally concerned that there are no SQIs with established performance targets to address reliability. Moreover, in our view, the lack of SQIs fails to meet the Commission's need to assure itself that service quality, as required by legislation, is being met.

The Commission Panel has separated SQIs into three categories: Safety, Customer Needs and Reliability. **Within these categories the Commission Panel approves the following SQIs proposed by Fortis:**

- **Safety**
    - **Emergency Response Time**
    - **Telephone Service Factor (emergency)**
- **Customer needs**
    - **First Contact Resolution**
    - **Billing Index**

- **Meter Reading Accuracy**
- **Telephone Service Factor (non-emergency)**
- **Meter Exchange Appointment**

In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include:

- **Safety**
  - **All Injury Frequency Rate**
  - **Public Contact with Pipelines**
- **Reliability**
  - **SAIDI (weather normalized) FBC only**
  - **SAIFI (weather normalized) FBC only**

Further, the Panel approves the following informational indicators:

- **Customer Satisfaction Index**
- **Telephone Abandon Rate**

and we direct Fortis to reinitiate the following informational indicators:

- **Generator Forced Outage Rate**
- **Transmission Reportable Incidents**
- **Leaks per KM of Distribution System Mains**

Telephone Abandon Rate, while reported by Fortis to be very low (T6:1275), has not been reported previously. The Panel considers this a useful measure in determining the level of service failure which is important given the Fortis proposal to lower its Telephone Service Factor SQI benchmark metric. The Panel has also directed Fortis to reinstate Generator Forced Outage Rate, Transmission Reportable Incidents and Leaks per KM of Distribution System Mains as informational indicators. While the Panel accepts the FBC argument that it has a portfolio of resources to draw upon if a generator fails, we note that a generation failure might impact power purchases thereby having an impact on rates. Because of this, it remains a valuable indicator. Likewise the Panel considers

Transmission Reportable Incidents a valuable informational indicator as it tracks the number of reportable incidents to outside agencies such as the BC Oil and Gas Commission and WorkSafe BC.

With respect to the proposed SQIs which have been approved, the Panel notes the position of Fortis that the Billing Index and Meter Reading accuracy may not be needed due to their consistently positive results, and agrees with Fortis' assessment of the value to customers. However, we recommend that this be revisited at some future Annual Review during the PBR.

The Panel has changed a number of informational indicators to benchmarked SQIs. Under Safety, AIFR and Public Contact with Pipelines have been added. In the view of the Panel both of these measures reflect important safety concerns. The Panel agrees with COPE that while the Companies cannot control the actions of their employees, they are accountable for them, and as such, are responsible to take steps to mitigate any harmful behaviour. Therefore, this is an appropriate SQI metric which should be benchmarked and managed. The Panel has a similar view with Public Contact with Pipelines. As pointed out, performance on this SQI is a reflection of public awareness and while the public cannot be controlled, FEI can heavily influence performance on this SQI through the activities it undertakes to create awareness.

Under Reliability, the Panel has added SAIDI and SAIFI as benchmarked SQIs for FBC. We agree with COPE's and CEC's arguments that the ratepayer should not be placed at risk over the PBR period by relegating this to an informational indicator. This SQI goes to the heart of concerns raised by interveners with respect to underspending of capital. While the Panel acknowledges that both of these measures have to be viewed over the longer term and may be more affected by weather in the short term, we consider them valuable as indicators of utility performance.

Level of Performance Benchmarks

With regard to existing SQIs, Fortis proposes changes to two performance benchmarks. FEI proposes that Emergency Response Time be reduced from its average performance level over the 2010 to 2012 period of 97.7 percent to a slightly reduced performance benchmark of 95 percent. **The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1,**

Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further directs that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period. The Panel acknowledges the concerns raised by Fortis with respect to the odds of falling below this level. This concern is dealt with in Section 2.3.3.3 where the introduction of "satisfactory performance ranges" is addressed.

A second change recommended by Fortis is related to FEI's non-emergency Telephone Service Factor. Fortis proposes to reduce the percentage of calls answered in 30 seconds to 70 percent from 75 percent. **The Commission Panel approves the reduction to 70 percent.** Although there is evidence that the industry standard is 80 percent, the Panel grants this approval for two reasons:

- Fortis reports a very low abandon rate in the 2 percent range for both FEI and FBC.
- FEI has implemented the call-back capability of its new system with substantial uptake. This mitigates to an extent the impact of unreasonable wait times.

In consideration of these factors, the Panel is persuaded that customer needs are being met. In addition, the Panel has ordered that in the future Fortis track phone call abandon rate as an informational indicator. If there is an increase in abandon rates the Commission may revisit telephone service SQIs in the future. **The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.** The Panel notes that all of these are sufficiently high to be reasonable or reflect an average of recent performance levels.

For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark. This methodology will be addressed further in Section 2.3.3.3.

A summary of these determinations and performance benchmarks are included in Table 2.26. **The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.**

Table 2.26 Approved Service Quality Indicators (SQIs)

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
		Safety SQIs		
Emergency Response Time[3,5]	Percent of calls responded to within one hour	97.7%	Percent of calls responded to within two hours	93%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All Injury frequency rate[1,5]	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64
Public contact with pipelines[1,5]	3 year average of number of line damages per 1,000 BC One calls received	16	N/A	N/A
		Responsiveness to Customer Needs SQIs		
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter Reading Accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Customer Satisfaction Index	Informational indicator	--	Informational indicator	--
		Reliability SQIs		
System Average Interruption Duration Index – Normalized[1,5]	N/A	N/A	3 year average of SAIDI (average cumulative customer outage time)	2.22
System Average Interruption Frequency Index – Normalized[1,5]	N/A	N/A	3 year average of SAIFI (average customer outages)	1.64
Generator Forced Outage Rate[2]	N/A	N/A	Informational indicator.	--
Transmission Reportable Incidents[2]	Informational indicator – Number of reportable incidents to outside agencies	--	N/A	
Leaks per KM of Distribution System Mains[2]	Informational indicator	--	N/A	

[1]Changed from an informational indicator to a benchmarked indicator

[2]Added as informational Indicator
[3]Benchmark changed
[4]Added benchmarked SQI
[5]Benchmark calculated as the average over the 2010, 2011 and 2012 period

2.2.3.3 Process to Review and Manage SQIs

The first issue the Panel must consider is whether holding the Companies to firm performance benchmarks is a reasonable approach to manage SQIs in a PBR context. Once this has been determined, the next issue is how best to implement a process to tie consequences to the failure to achieve reasonable performance on SQIs.

FEI explains that in establishing the SQI benchmarks it has relied on the Company's performance over recent years or on general industry standards. (FEI Exhibit B-1-1, Appendix D7, p. 2). It believes it is appropriate to base the proposed benchmarks on performance in recent years because the benchmarks are then reflective of the costs required to provide the service levels. (FEI Exhibit B-6, BCPSO 1.26.1) The use of a rolling average acts to smooth out annual results providing for a longer term indicator of any trends that may be developing. (FEI Exhibit B-6, BCPSO 1.26.1; FBC Exhibit B-7, BCUC 1.60.1.1)

As noted earlier, COPE has taken the position that the best way to determine SQIs and reduce volatility in results is to rely on a three year average for determining performance benchmarks for SQIs. Fortis has responded by pointing out that a drawback to relying upon an average is that actual amounts will fall above and below the average. Thus, what might be interpreted as a decline in service may not be reflective of what is occurring. (Fortis PBR Reply pp. 82–83)

Fortis has noted that in using a three-year average to set the SQI benchmark, by definition there will be years within the average that are below the average. For these reasons the Companies do not see the merit of tying specific consequences to the SQI benchmark targets. (Fortis PBR Reply, pp. 82-83)

Commission Determination

The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.** The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences. Performance benchmarks would continue to be determined which would serve as a target only and failure to reach them would not have consequences.

<u>Determining the Performance Benchmarks and an Acceptable Performance Range</u>

While the Panel agrees with Fortis that a three-year average helps to smooth out annual results, we do not agree with the use of a rolling average. Use of a rolling average is inconsistent with the concept of a satisfactory performance range as it could perpetuate a downward trend. The Panel agrees with BPCSO that setting the benchmark based on the last three-year period for which annual data was available (2010, 2011 and 2012) establishes the benchmark at a level that is reflective of the costs required to provide this level of service. The Panel has previously approved a performance range which provides for normal annual variability. **The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.** Once set, these will serve as performance benchmarks for the balance of the PBR.

The Commission Panel has considered options for setting an acceptable performance range for SQI metrics. In our view this is not simply a matter of setting a plus or minus percentage range that would be applied to all SQIs. Rather, a variety of factors like the economy, weather and the potential for variation must be considered in determining the range**. For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.** An appropriate time to deal with this is in the period leading to the first Annual Review. Consultation among the parties should form a part of the process with recommendations flowing from it. **In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.**

In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

<u>Failure to Meet SQI Benchmarks</u>

Where one or more of FEI or FBC's SQI performance metrics are outside the established range, the matter will be handled as part of the Annual Review. **Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.**

Where, after due process, the Commission finds that Fortis has failed to provide adequate service and the failure was, in whole or in part, due to the actions (or inactions) of Fortis, the Commission may reduce the share of earnings above the allowed rate of return that would otherwise flow to the Company. The reduced share of earnings would be credited to customers in the form of a compensation credit. **The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.**

When assessing the magnitude of any reduction in each Company's share of the incentive earnings, the Commission will take into account the following factors:

- Any economic gain made by each Company in allowing service levels to deteriorate;
- The impact on the delivery of safe, reliable and adequate service;
- Whether the impact is seen to be transitory or of a sustained nature; and
- Whether each Company has taken measures to ameliorate the deterioration in service.

Where there are no incentive earnings to share (i.e. the rate of return achieved by the Companies are at or below the approved rate of return), the Commission may still assess whether the level of service provided by the Company is adequate. In this case, the actions taken will be driven by the provisions in the UCA. This might include ordering Fortis, under section 25 of the UCA, to take certain actions to remedy a service deficiency or the imposition of an administrative penalty under section 109.2 of the UCA.

2.2.4 Off-Ramps

Off-ramps are described in the Companies' Applications as "a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances" (FBC Exhibit B-1 pp. 69–70; FEI Exhibit B-1 p. 77). This section addresses off-ramps that could lead to a broader review of the entire PBR Plan and potentially to a termination of the PBR Plan altogether.

There are two off-ramp triggers proposed, a financial trigger and a non-financial trigger. The financial trigger is engaged when the post-sharing earnings of the Company exceeds or drops below the allowed ROE by 200 basis points. Given the 50:50 earnings sharing mechanism, this means that actual earnings would have to be above or below the approved ROE by 400 basis points to trigger a review of the PBR Plan. Fortis states that the allowed variance between the actual and approved ROE before the off ramp is triggered must be large enough to incent the Companies to pursue efficiencies while at the same time be limited enough to safeguard against potential excessive profits or losses. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

Fortis proposes that the non-financial trigger would be engaged if the Companies' service levels fell to an unacceptable level. In the Companies' view, only a "sustained serious degradation of the SQIs" would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet an SQI(s) must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

2.2.4.1 Financial Trigger

Previous Fortis PBR Plans in British Columbia

Neither of the earlier PBR plans of FEI or FBC included a firm quantitative reopener or off-ramp. However FEI and FBC, as part of the Annual Review process had the right to request a change or termination of the PBR Plan if there were unacceptable outcomes associated with it.

B&V states: "[t]his provision does not represent the best approach to addressing serious issues with a PBR plan." However, B&V sees the provision as "understandable" within a negotiated settlement that includes a number of other provisions. (FEI and FBC Exhibit B-1-1, Appendix D1, pp. 46–47)

The 2004 FEI PBR Plan had a trigger of +/- 150 basis points around the approved ROE (after earnings sharing) but this was not considered an automatic off-ramp. It was open for parties to request a Commission review of the 2004 Plan if the threshold was exceeded. The 2007 FBC PBR Plan had a trigger mechanism of +/- 200 basis points around the approved ROE but this was not an off-ramp. If the earnings threshold was exceeded, the earnings variance (positive or negative) would be placed in a deferral account for review and disposition at the next Annual Review. (Fortis PBR Final Argument, p. 56)

In the previous PBR period, the Companies exceeded their allowed rate of return by a maximum of 145 basis point (FEI) and by 115 basis points (FBC) (Exhibit B2-11, CEC 45.4). Considering its previous PBR plan, FBC states: “FBC’s going-in rates for this PBR Plan already incorporate substantial productivity savings achieved through the 2007-2011 PBR period, and those that have been realized in the 2012-2013 period through a renewed productivity focus. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2007 Plan.” (FBC Exhibit B-1, p. 5)

Intervener Submissions

CEC submits that the +/- 200 basis point differential post-sharing is too high. CEC notes this is equivalent to a +/- 400 basis point variance if there were no earnings sharing mechanism and is 50 basis points higher than the previous FEI PBR plan. CEC states that there is “little justification for either the number itself or for an increase.” The proposed financial trigger is viewed by CEC as relatively high in comparison to other jurisdictions where the trigger is +/- 300 basis points with no earnings sharing mechanism. (CEC PBR Final Argument, pp. 165–166)

CEC recommends that the financial off-ramp should be set at the level of +/- 150 basis points (CEC PBR Final Argument, p. 171). CEC further advocates the use of a multi-pronged trigger to better protect customer interests if a PBR plan is approved (CEC PBR Final Argument, pp.167–168).

CEC also contends that the financial trigger is asymmetric in that Fortis, regardless of the PBR trigger, has the ability to file a cost of service application at any time if its actual rate of return falls too far below the allowed return. CEC does not see the consumer having the same redress if actual ROE is consistently significantly above the allowed ROE but below the trigger. CEC further asserts that Fortis could moderate or apply a cap to its earnings to avoid triggering an off-ramp.
Fortis refutes the suggestion that the off-ramp is asymmetric. Fortis submits that customers have the same opportunities afforded by an off-ramp as the Companies. Fortis may address financial

distress through an application to the Commission while customers may use an equivalent mechanism of filing a complaint to the Commission. In addition, Fortis states there is nothing in the PBR Plan "that would (i) purport to unlawfully fetter the Commission's discretion in the future, or (ii) skirt the rule against retroactive ratemaking." (Fortis PBR Reply, pp. 52–53)

Fortis also refutes the concept of a multi-prong trigger. In response to a CEC information request, stating it would not support a two-year trigger concept because:

- Dual trigger points are more prone to controversy for potential gaming concerns. (i.e. by increasing expenditures in one year to lower the actual ROE to compensate for a high ROE achieved in a previous year); and
- Fortis intends to pursue efficiencies and savings on a consistent basis throughout the PBR term. In Fortis' view this means that if the two-year trigger was set significantly below the single year trigger, there is a high likelihood that if one year's results were above the two-year trigger level, the subsequent year likely would be as well. This would trigger the off-ramp to the detriment of achieving longer-term benefits under the plan. (Exhibit B2-11, Fortis CEC 3.45.3, pp. 114–115)

Fortis submits that CEC has provided no rationale to explain why a multi-prong trigger point is more appropriate than a single trigger point. (Fortis PBR Reply, p. 53)

ICG supported the off-ramp elements of the Fortis application (ICG PBR Final Argument, p. 25). No other interveners addressed the financial trigger in the off-ramp.

Commission Determination

The Commission Panel views the triggering of an off-ramp as setting in motion a two-stage process. The first stage consists of a process before the Commission to assess potential remedies to the situation, including the potential for amending or re-calibrating the PBR plan to allow it to continue. A second stage to the process would be triggered if satisfactory solutions could not be found through modification of the PBR plan. This stage would deal with how to exit from the plan. This could include a variety of options from going back to a cost of service methodology to a redesign of the PBR.

With respect to the financial trigger, the Commission Panel agrees with Fortis that it should strike a balance between being high enough to incent the utility to vigorously pursue efficiencies and savings while being low enough to provide a safeguard for customers and the utility if either profits or losses become excessive. The applied for +/- 200 basis points post-sharing means that the achieved ROE before the earnings sharing is calculated would be +/- 400 basis points. This compares to the one year trigger point set in Alberta at +/- 500 basis points (with no revenue sharing) and the OEB trigger point of +/- 300 basis points, both of which are criticized by Fortis' consultant as being too broad. The AUC tempered its one-year trigger by also imposing a two-year trigger of +/- 300 basis points. The Panel notes that Fortis' expert witness testified that "I'm not aware that any utility would get to the point of being 200 basis points below their allowed return without filing a cost of service application" (T4:791).

In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year vary from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years, the off-ramp will be triggered.

The Panel is of the view that a 50 basis point differential is in all likelihood not significant enough to give rise to Fortis' concern regarding multi-year triggers being "significantly below" single year triggers.

Regarding intervener concerns that the single-year trigger is too high, the Panel notes that even with substantial productivity savings, Fortis did not exceed their allowed rate of return in their previous PBR periods. The Panel is of the view that the trigger points approved in this Decision will not stifle efficiency efforts and will provide an appropriate balance of protection for the Companies and the ratepayers.

2.2.4.2 Non-Financial Trigger

Fortis proposes that the non-financial trigger would be engaged if service levels fell to an unacceptable level. In the Companies' view only a "sustained serious degradation" of service quality, as measured by the SQIs, would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet one or more SQIs must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 2)

Fortis also submits that there are less drastic options to deal with declining service levels, noting that SQIs will be reviewed at each Annual Review. If appropriate, the Companies will work cooperatively with the interveners and the Commission to address any performance deficiencies. (Fortis PBR Final Argument, p. 58)

Fortis further submits that in the event there is a finding that some action of Fortis directly caused or contributed to a decline in service quality, the Commission has options under the UCA that include:

- Ordering Fortis to take certain steps to address service quality; and
- The power to levy administrative penalties after a hearing if the Companies breach the Commission order.

(Fortis PBR Final Argument, p. 155)

<u>Intervener Submissions</u>

CEC raises a number of concerns with respect to the non-financial trigger and submits that:

- the non-financial triggers act as a 'framework for determining whether there is need for a complete regulatory review of the PBR plan' rather than as an off-ramp under which a complete regulatory review of the PBR would be undertaken;
- there is no obligation to maintain specific benchmarks;
- the term "sustained serious degradation" is extremely vague and open to interpretation and debate and should be defined by the Commission.

CEC agrees that the off-ramp should not be triggered if the issue is not caused by the Companies' actions. CEC recommends that the definition of when the off-ramp is triggered should encompass the concept of "prudent Utility management." (CEC PBR Final Argument, pp. 168–169)

BCPSO notes that in the 2004 PBR there was an option for participants in the Annual Review to make submissions to limit incentive payments to the Company if a deviation from an SQI Benchmark was significant. BCPSO recommends that this option be included in the current PBR plan. (BCPSO PBR Final Argument, p. 20)

COPE submits that:

- The Applications and evidence are "bereft of any guidance" as to the definition of a "sustained serious degradation of service quality" (COPE Final Argument, p. 7);
- A review as to whether there was a serious degradation in service quality would not occur until the Mid-term Review. This, in COPE's view would make it "difficult, if not impossible" for the off-ramp to be executed before the final days of the PBR (COPE Final Argument, p. 9);
- Fortis intends the off-ramp to be triggered only if there is a consensus it should be. This, in COPE's view, makes the off-ramp meaningless (COPE Final Argument, p. 10); and
- Even if it is determined that there is a serious sustained degradation of the SQIs, and the off-ramp provision is executed this would still not result in an adjustment to the financial results achieved. (COPE Final Argument, p. 13)

ICG supports the off ramp provisions of the FBC Application (ICG Final Argument, p. 25). Other interveners did not comment specifically on the merits of the non-financial trigger.

Commission Determination

<u>Definition of "Sustained Serious Degradation"</u>

Several interveners have raised concerns with respect to the lack of definition as to what encompasses a sustained serious degradation of service that would warrant the triggering of a review of the complete PBR plan and potentially the termination of the plan. Fortis, by stating that the Mid-Term Review would be the earliest time one could assess whether serious degradation has occurred, implies that "sustained" means degradation is ongoing over two or more years. The concept of what constitutes "serious" degradation is even more vague, with Fortis stating that failure to meet one or more benchmarks does not necessarily constitute unacceptable performance, particularly where under normal conditions there are circumstances that impact the SQI that are outside the Companies' control. (Fortis PBR Final Argument, p. 58)

The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical. The determination of a sustained serious degradation entails judgments that can only be made based on the specifics of the circumstances that have given rise to the purported degradation. The Panel recommends the following criteria as the basis of the assessment of whether "sustained serious degradation" has occurred:

- Has the degradation persisted for two or more years and can it be reasonably anticipated to occur in the future?
- Has Fortis undertaken actions that are expected to mitigate the deficiency?
- Is the degradation due to random events that are not expected to recur?
- If the events impacting the SQI also are affecting other utilities, are the other utilities experiencing the same degradation of service quality?

In Section 2.3.3.3 the Panel sets out the consequences if Fortis fails to provide adequate safe and reliable service. We have also added additional SQIs to those proposed and amended some of the filed SQIs. We are of the view that this provides adequate incentive to the Companies to maintain appropriate service levels. This should render less likely the occurrence of "sustained serious degradation" of service quality.

Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate. In particular, parties are requested to bring recommendations forward to the Commission where there have been a "sustained serious degradation" of service.

2.2.5 Capital Expenditures – What's In What's Out

2.2.5.1 Introduction

Fortis proposes to include only a portion of its capital spending in its formulaic capital spending envelope. This gives rise to a number of issues, including:

1. What is the appropriate base capital upon which to base the formula?
2. What proportion of capital spending should be included? What, if any, capital projects should be excluded from the formula?
3. How can capital expenditures, which are often lumpy, be appropriately matched to a much less lumpy formula driven spending envelope?
4. How can the ratepayer be protected from chronic underspending relative to the formula driven spending envelope?
5. How can Fortis be protected in the event that necessary capital expenditures drive the actual capital expenditures above the formula driven spending envelope?

The Panel will review these issues in the following sections. First we will review the approach that Fortis is proposing and how capital has been treated in previous Fortis PBR plans. We will also review the AUC's approach to PBR capital as it has been widely discussed in this proceeding.

The Panel considers the issue of the base capital in Section 3.1.3 of this Decision.

2.2.5.2 Treatment of Capital during Previous PBR Periods

Prior to 2004, PBR plans for FBC covered only O&M. All capital spending was approved separately. For FEI, in the PBR plan in effect from 2005 to 2009, "capital expenditures were escalated by a formula that incorporated forecast inflation and productivity factors. It included a 50/50 earnings sharing mechanism between customers and shareholders". FEI further states that "[e]ach year, the capital expenditure forecasts were developed using the customer additions forecast for growth capital and the forecast average number of customers for all other base capital. The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth." FEI adds that CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes. (FEI Exhibit B-1, pp. 34–35)

FEI states that there were "significant capital savings" achieved over the term of its PBR period and that benefits to ratepayers included:

1. Reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Rebasing of the savings in the opening rate base and future rates after the PBR ended.

FEI further describes the capital expenditures:

> "During the 2004 PBR, FEI's actual base capital expenditures for the six-year period were $490.million. This was $80.1 million, or about 14 percent on average, below the formula- allowed capital expenditures of $570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI's actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately $1 million above the formula-based amount." (FEI Exhibit B-1, p. 38)

CEC submits that FEI capital underspending during the previous PBR period shows a total of about $80 million with the annual amounts showing about $9 million in the 2008 to 2009 period. The aggregate benefit from underspending the capital formula was approximately $50 million of which the Company received half or $25 million. This benefit grows and accumulates annually until rebased at the end of the PBR period. Rebasing earlier when the PBR period expired and not extending the PBR process would have saved customers approximately half of the capital payment to the Utility.

It further submits that "[t]his is an example of the failure to understand PBR processes properly. CEC had such a misunderstanding when it participated in extending the previous PBR term and failing to rebase the formula as quickly as possible. CEC has had the advantage of this regulatory process to learn just how poorly PBR incentives are aligned with customer interests. CEC submits that the Commission should ensure that such an error does not happen again." (CEC PBR Final Argument, pp. 90–91)

2.2.5.3 Fortis' Proposal

The formula proposed by FBC for all capital and by FEI for sustainment and other capital is:

$$C_t = C_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *C=Capital Expenditures subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

and for FEI's growth capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The Panel has reviewed the growth terms for the above formulas in Section 2.2.6 of this decision. In addition, the I- and X-Factors were reviewed in Sections 2.2.2 and 2.2.3, respectively. The Panel will not comment further on the formulas themselves, but will now review the size and nature of capital projects to which the formulas apply along with the consequences of underspending and overspending relative to the formula.

2.2.5.4 CPCN Capital

Fortis proposes separate ratemaking treatments for CPCN projects. CPCN expenditures will be excluded from the formula and will continue to be subject to the existing criteria for determining the need for a CPCN application. It states that "[m]ajor capital project expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service." (FBC Exhibit B-1, p. 55)

For FEI, all projects in excess of $5 million require a CPCN. For FBC, a CPCN is required for projects in excess of $20 million and any other projects: 1) likely to generate significant public concerns; or

2) that FBC or the Commission wishes to handle through a CPCN; or 3) that a credible majority of stakeholders believes should involve a CPCN. (FEI Exhibit B-1, p. 250; FBC Exhibit B-1, p. 226)

Fortis states that "[t]here is no practical way to capture CPCN capital projects under the PBR Plan." In its view, "[t]he nature of capital expenditures is such that the controllable and generally planned investments are included in the plan while other capital should be outside the plan." Fortis also states that Enbridge has proposed a similar customized PBR Plan with separate capital updates for the later years of the plan. (FEI Exhibit B-11, BCUC 1.10.2.; FBC Exhibit B-7, BCUC 1.19.2)

B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It states that it is akin to the adoption of a capital tracker, which is incorporated in PBR plans elsewhere. (FBC Exhibit B-1, p. 55) Fortis submits that "The AUC has been approving significant capital trackers, which are similar in nature to FortisBC CPCNs." (Fortis PBR Final Argument, p. 48)

PEG agrees that the Fortis proposal is tantamount to a tracker treatment for CPCN costs. However, in its view, the eligibility requirements are unusual and incentives to contain the cost of capex for these projects are a concern. Dr. Lowry states that "[i]f you would have a more conventional CAPEX tracker or at least raise the materiality threshold, the problem would — most of the problem would go away." (FBC, Exhibit C1-22, BCUC-IR2, 2.7.2; T7:1487)

With regard to FBC's proposed base capital formula driven spending envelope, ICG submits that "[t]he replacement of detailed project by project analysis of the past with a formula based approach should not be expected to provide better capital expenditure targets. It is more likely that such a change will result in excess returns not related to efficiency gains." (ICG Final Argument, p. 19)

2.2.5.5 Fortis' Proposed Dead-Band

Fortis states that "limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%" (FEI Exhibit B-1, p. 8; FBC Exhibit B-1, p. 40).

To this, BCSPO points out that "the proposed deadband does not take into account the fact that capital is cumulative and that, if there is a consistent under spending of 9.5% per year, this will result in capital expenditures that are 46% lower than one year's capital. As such, in addition to the annual threshold of 10% for capital rebasing, BCPSO submits there should be a cumulative threshold that reflects the cumulative nature of capital." (BCSPO PBR Final Argument, p. 10)

2.2.5.6 Fortis' Expected Capital Expenditures during PBR

2.2.5.6.1 FEI's Capital Spending

FEI estimates approximately $672 million to $689 million of proposed formula driven capital expenditures over the PBR period. FEI believes this allowed capital under PBR provides suitable incentive to find efficiencies for capital expenditures without raising concerns of compromising safe, reliable natural gas service or service quality. (Exhibit B-11, BCUC 1.10.3)

FEI lists the following CPCN projects that will be excluded from the capital formula:

1. The Huntingdon Station Bypass. Loss of functionality of certain sections of the Huntingdon Station can lead to the complete outage on both the CTS and FEVI systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station, is necessary to reduce the risk of a service outage estimated at approximately $7 million.
2. Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station to stabilize most of the Right of Way in the Burns Bog to mitigate the risk of ground movement and associated pipe damage. No estimate provided.
3. The Coastal Transmission System and Intermediate Pressure System sustainment projects, required in order to ensure the ongoing safety, integrity, and reliability of the system, estimated at approximately $220 million.
4. The Kingsvale-Oliver Reinforcement Project (KORP). The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British 26 Columbia gas to the Pacific Northwest and California markets. *Estimated at $440* million*.*

(FEI Exhibit B-1, pp. 250–253; FEI Exhibit B-11, BCUC 1.10.3; T4:665)

Coastal Transmission System upgrades and KORP alone amount to approximately the same amount as the projected formula driven spending in the entire PBR period (Exhibit B-11, BCUC 1.10.3).

2.2.5.6.2 FBC's Capital Spending

FBC estimates a little over $300 million of formula capital in the PBR period. The estimated CPCN projects amount to somewhat less than half of the estimated formula capital. FBC lists the following proposed CPCN projects:

Table 2.27 Proposed FBC CPCN Projects

Project	Application Filed	Est Start Date	Est In Service Date	Est Cost ($ million)
Kelowna Bulk Transformer Capacity Addition	2016	2017	2019	14.5
Grand Forks Transformer Addition	2016	2017	2019	5.9
Ruckles Substation Upgrade	2015	2016	2019	5.9
Central Okanagan Substation	2017	2018	2019	24
Grand Forks to Warfield Fibre Installations	2014	2014	2015	4.8
Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2016/2017	2015	2033	21.6
Kootenay Long Term Facilities Strategy	TBD	2014	2016	16.4
Upper Bonnington Unit 1, 2, 4 Refurbishment	2015	2016	2019	21.0
Total				**114.1**

(Source: FBC Exhibit B-25, BCUC 2.45.1)

2.2.5.7 The AUC Approach

B&V summarized the criteria for the capital tracker mechanism adopted by AUC as:

1. The project must be outside of the normal course of the company's ongoing operations
2. Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party; and
3. The project must have a material effect on the Company's finances

(FEI Exhibit B-1-1, Appendix D1, p. 8)

PEG considers the AUC's capital tracker requirements to be overly broad. It states that capex projects potentially eligible for tracker treatment should have some combination of the following attributes:

- Large (i.e. having a material effect on the company's finances)
- Non-revenue producing
- Not associated with unusually rapid O&M productivity growth that permit project self financing;
- Not reflected in the productivity research on which the X-Factor is based; and
- Required by a government agency or other powerful external party.

(FBC Exhibit C6-21, BCUC 2.9.1)

2.2.5.8 Issues Arising

2.2.5.8.1 The Lumpiness of Large Capital Expenditures

Fortis states that:

> "[g]iven the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system." (FBC Exhibit B-1, p. 55)

CEC submits that "it is clear that CPCN's for major capital projects replacing portions of the system could and would impact the future sustainment capital requirements, as would such projects aimed a [sic] implementing life extension options. CEC submits that this is an area of very loose discipline with regard to the operation of a PBR formula for capital. CEC submits that the Commission can only resolve this by confining the types of capital allowed in the PBR formula." (CEC PBR Final Argument, p. 98)

Fortis states that "These projects, and the lumpiness of the expenditures associated with them, are well outside normal steady-state operations. Indeed, there is no provision for expenditures of these types in the determination of the 2013 Base Capital; hence classification of these projects as Major Capital is appropriate." (Exhibit B2-8, BCUC 3.8.8)

BCPSO expresses concerns about "the potential for the utilities to 'game the CPCN process' by grouping together projects that have historically been included (or ought to be included in) in base capital." In the view of BCPSO, "[i]f Fortis is able to lump costs together to meet the threshold for a CPCN, they may be able to either have costs added to O&M, or have capital that was below the CPCN threshold in the past, now be treated as CPCN, and thus reduce what was historically outside CPCN." (BCPSO PBR Final Argument, p. 21)

With regard to FBC, CEC states that "[a]n inspection of the CPCN projects suggest they are generally routine but lumpy investments, such as the construction of a new substation" (FEI Exhibit C1-13-1, CEC Response to BCUC 1.13.2).

2.2.5.8.2 A Materiality Capital Exclusion Threshold

As previously noted, FEI's $5 million CPCN threshold is a quantitative criteria. Capital projects less than $5 million do not generally require a CPCN although the Commission could so require it. Accordingly, FEI's threshold is very much akin to a materiality threshold that is a capital exclusion based solely on a dollar figure. However, FBC's CPCN criteria, although incorporating a materiality threshold of $20 million, are much broader and allow for the Company to determine whether a CPCN is required for capital projects less than $20 million. The notion of a materiality threshold for both companies was explored in the proceeding.

Regarding FEI's $5 million CPCN threshold, Ms. Roy stated that it was originally set in 2004 and "it may be low…. Five million dollars is a fairly small number" (T4:665). However, she also stated that FEI usually don`t have a lot of capital projects with a cost of 5 million, and that "[w]e sometimes have some that are 8 to 9 [million]¸and then after that they tend to jump to more than $20 million". (T4:665–666)

Mr. Swanson stated that when the $20 million CPCN threshold criteria was set for FBC, it represented roughly 1 percent of revenues (T4:665). Ms. Roy commented that "one percent of our [FEI's] delivery revenue requirement is about $65 million. That's a pretty high CPCN threshold. It would definitely require some kind of recalibration of either the base or the X-Factor". (T4:666–667)

2.2.5.8.3 Timing of Capital Spending

Fortis states that "[t]he Companies have some control over capital spending otherwise it would be inappropriate to include capital in the PBR formula." (Fortis Exhibit B2-11, CEC 3.5.2)

CEC submits that "[i]n fact they have quite a lot of judgment control on when to undertake sustainment capital but very little control over the need for the sustainment capital." In its view, "[i]t is the control over the timing of the sustainment and other capital that enables the Utilities to underspend a capital formula without consequences, particularly when the capital formula has been set sufficiently high." It submits that the Commission should focus close attention to the areas where the Utilities have judgment latitude because these are the highest potential areas where unwarranted rewards for no real savings can occur." (CEC Final Argument, p. 96)

2.2.5.8.4 Impact of CPCN Capital on O&M

Capital projects funded outside the PBR formula may give rise to subsequent reductions in spending relative to the formula driven O&M spending envelope. For example, a CPCN project that is tracked outside the formula to replace an older leak-prone pipe will, in all likelihood, reduce the ongoing maintenance requirements.

FEI states:

> "CPCN projects may reduce some O&M costs. Those O&M reductions may or may not be covered under the PBR Plan. For example, a CPCN project that reduced

> electric lines losses results in lower purchased power expenses and would pass through automatically because purchased power costs are not part of the PBR Plan mechanism. A similar result would occur for the gas system where new pipe replaces older leakier pipe and the quantity of lost and unaccounted for gas would be reduced. Some O&M expenses such as leak surveys are still required even for new installations so there is no saving at all. Finally, there may be fewer repairs on the new segments of main but it is also true that other segments have aged and the expected repairs increase." (FEI Exhibit B2-8, BCUC 3.11.3)

FEI also submits that "all CPCN applications, whether submitted during the PBR term or during a cost-of-service RRA test period, should include a full assessment of the costs and benefits of the project. This is a standard requirement in the Commission's CPCN Application Guidelines." (FEI Exhibit B2-1 BCUC 3a.305.1)

Fortis agrees that CPCN projects may reduce some O&M costs and that these reductions "may or may not be covered under the PBR Plan." However, when asked about the upcoming CPCN projects, FBC stated that "[n]one of the projects identified above are forecast to result in incremental capital and/or O&M cost savings during the proposed PBR term and trailing ECM window." (FBC Exhibit B-24, BCUC 2.43.2; Exhibit B2-8 BCUC 3.11.3) FEI argues that "not all CPCN projects generate future savings. Indeed some CPCN projects involve both capital and/or O&M cost increases." (FEI Exhibit B2-8, BCUC 3.11.3)

Fortis further states that:

> "[t]he impact of CPCN projects and the 'potential' savings or costs that may result from them are already accounted for in the PBR formula through FEI's proposed X-factor. As discussed in B&V's TFP studies, the electric and natural gas utility industry-wide productivity factors are well into the negative zone while FEI's and FBC's proposed X-factor is a positive 0.5%. A contributing factor to FEI and FBC being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans." (FEI Exhibit B2-1 BCUC 3a.305.2)

Fortis submits that PEG's discussion "is premised on a plan such as that that exists in Alberta. And even then, on the type of capital tracker that the AUC has moved away from, recognizing that it is unworkable in practice." (T8:1399)

CEC submits that "all O&M savings or other cost reduction that are a result of CPCN activity should be flowed through as a matter of course and that the Utilities proposition to not do so is misaligned with customer interests" (CEC PBR Final Argument, p. 85).

In the case of FBC, Mr. Swanson testified that "what we found is over that five-year period, the net result of all those CPCNs was actually an increase in O&M. So had we flowed all that through the formula you would have in fact increased O&M not decreased O&M because there's not a lot of CPCNs where … the theoretical CPCN where you invest in some piece of infrastructure that makes a bunch of labour go away. Those types of CPCNs simply don't often exist in our world." (T2:332)

However, CEC cites a specific example of O&M benefits resulting from a capital project. FBC proposes to track AMI outside its PBR plan which CEC interprets to mean that it does not impact the PBR formula. It states that the AMI impact for 2018 includes savings of $4.4 million in meter reading savings which are partially off-set in new operating costs for a net reduction of approximately $2.8 million in O&M. When the savings are excluded, the PBR O&M forecast increases from $63.3 million to $66.1 million. (CEC Final Argument, p. 83)

CEC submits that "there is no process to ensure that all AMI O&M benefits are captured and excluded. The AMI hearing identified many benefits that were not defined and or estimated. To the extent any of these are O&M related and outside of the company process for deducting them to flow them through to customers, they may result in sharing with the Utility shareholder inappropriately. CEC submits this would be a misalignment with customer interests." (CEC Final Argument, p. 83)

2.2.5.8.5 Impact of Price Spikes

CEC submits that

> "the potential for capital costs to be driven by market supply demand conditions resulting in significant price spikes, which subsequently have subsided. The nature of such perturbations in the market makes the application of a formula highly problematic because they can lead to potential under allowance for capital expenditures and risks to the system or if embedded into the base potential over

> allowance in the formula putting the customers at risk of paying for phantom savings of underspending an overly generous formula. CEC submits that the current PBR proposals for capital are more likely to contain the later [sic] problem." (CEC PBR Final Argument, pp. 106–107)

Commission Determination

The Panel will address the issue of capital excluded from formula driven spending by addressing the following questions:

1. Should there be any capital exclusion criteria at all?
2. Is the CPCN Criteria an appropriate Exclusion Criteria?
3. Is a Dollar Threshold Appropriate?
4. What should the Quantum of a Dollar Threshold be?

<u>Should there be any Capital Exclusion Criteria at all?</u>

In the Panel's view, the more capital excluded from formula spending, the fewer benefits of PBR accrue to ratepayers and shareholders alike. Excluding significant amounts of capital reduces the ability of the utility to achieve operational efficiencies. However, it also provides opportunities for a utility to game the system, such as by combining smaller projects into larger projects that will be excluded from the formula. Also, by including more capital in the formula, larger, and potentially lumpier, projects are included. This gives rise to challenges to the utility to manage and also possibly increases risk to ratepayers and shareholders alike.

The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope. There are certain capital projects that are outside the normal course of business, that the utility is required to undertake and that the utility has little or no control over should not be included in the formula. In our view, these projects should be accorded exogenous treatment, in much the same way that certain O&M expenses are.

It also may be appropriate to consider an exclusion criteria based on the size of the project and we will examine this issue in the following sections.

Is the CPCN Criteria an Appropriate Exclusion Criteria?

The Panel is not persuaded there is any basis to link exclusion from CPCN requirement to exclusion from the PBR formula. Section 45 of the UCA requires that "a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity requires or will require the construction or operation." Exclusion from this requirement is based on a balance of regulatory efficiency and the broader public interest. Otherwise, all capital projects would be subject to CPCN requirements.

In the case of FEI, the CPCN threshold limit amounts to a materiality threshold of $5 million. However, in the case of FBC, with the number of projects below $20 million subject to CPCN requirements, the CPCN threshold doesn't provide a clear, transparent materiality limit. In proposing the CPCN exclusion criteria as the PBR capital exclusion criteria, Fortis is effectively arguing that in the case of FEI a $10 million dollar project is too lumpy, yet for FBC a $10 million dollar project could, unless otherwise subject to CPCN requirements, be managed as part of the formula spending envelope. In the Panel's view, this supports the conclusion that the use of CPCN criteria as an exclusion criterion for the PBR formula is arbitrary. Further, the CPCN requirements do not differentiate between routine capital projects and projects that are not routine. Therefore, they are not a good indicator of the exogenous nature of the capital project.

Is a Materiality Threshold Appropriate?

Many parties argue that the lumpy nature of large capital projects is more likely to result in a variance between formulaic and actual spending. The Panel does not agree that larger capital projects necessarily have a propensity for lumpiness. It is not necessarily the magnitude of the project that contributes to the lumpiness, but the annual spend-which depends upon both the total spending and the duration of the project-and the number and nature of other projects undertaken concurrently. For FBC, for example, under the formula, approximately $20 million to $30 million dollars will be spent each year on a variety of sustainment projects with different costs and durations. There does not seem to be a significant difference between a one-year project with a cost of $2 million that is included in the capital formula spending envelope and $2 million spent in one-year of a three year $6 million CPCN project that is excluded from the formula.

As CEC asserts and Fortis acknowledges, the utilities do have some control over capital spending. The Panel expects the utilities to take a proactive role in the management of their capital projects, regardless of the materiality of the threshold, so there is as little variance as possible while ensuring that there is no underspend of the type that CEC alleges have occurred during the previous PBR period.

Parties also raised concerns that there is an opportunity for the utility to combine smaller projects into a larger project that will trigger a CPCN requirement, and thereby exclude all of those smaller projects from the PBR formula driven spending envelope. Unless those smaller projects are replaced by other small projects, the result will be, all else equal, an under-spend relative to the formula driven spending envelope.

There are two provisions in the PBR mechanism that mitigate the impact of this and thereby protect ratepayers in this eventuality. The first is Fortis' proposed dead-band around the actual capital spend relative to the spending envelope, which would be triggered if the under-spend was of sufficient magnitude and/or duration. **The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula.**

In addition, the earnings sharing mechanism, which the Panel approved elsewhere in this decision, ensures that ratepayers share half of the benefits of that underspend, although that may amount to returning half of the money that has, in some sense, been over-collected from them because of the underspend.

In the Panel's view, a further potential mitigation is to increase the limit of the size of capital project that is subject to formula spending. The larger the limit, the less likely that smaller projects can be combined.

If a Materiality Threshold is Set, at What Level Should it be Set?

The Panel is of the view that, if a materiality threshold is appropriate, it should be set at such a level that considers both the lumpy nature of projects and the ability of the companies' professional management teams to manage that lumpiness. The threshold should reflect a balance of risk with the benefits of the operational efficiencies that arise from the more holistic approach to management provided by the inclusion of capital within the formulaic spending envelope. In the following section the Panel will consider the quantum of the threshold.

However, a number of arguments have been raised against a higher materiality threshold. FEI and FBC argue that a contributing factor to being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans. The Panel does not agree with this argument. The Panel has applied relatively small stretch factors to each utility. Further, neither the B&V nor the PEG study excluded capital spending for CPCN Projects or even applied a threshold of materiality for capital spending in their studies - the X-Factor accepted by the Panel is based on a TFP trend study that included all of the capital spending of the utilities. Accordingly, as Dr. Lowry testified, if the X-Factor is to be applied to a capital spending envelope that is substantially less, it requires adjustment. The Panel has not made any such adjustment and considers the X-Factor approved in this proceeding to be appropriate for use with an increased materiality limit. If any adjustment is required, in the Panel's view an upward adjustment may be appropriate to account for the proposed CPCN-based exclusion criteria. However, at this time, the Panel declines to make such an adjustment.

Interveners raise concerns about the formulaic approach to capital spending generally, arguing that even the proposed approach, with its CPCN exclusion, leaves the utilities significant opportunity to underspend. To the extent that this is the case, increasing the threshold will provide even greater opportunities to underspend.

The Commission Panel does not disagree with these intervener concerns. However this is not sufficient reason to warrant either disallowing the capital spending formula entirely or even keeping the CPCN limit as proposed. It is only by increasing the amount of capital covered by formula that the full benefits of PBR can be achieved.

However, the Panel does not consider it appropriate to set a different exclusion threshold at this time and will seek further comment on this issue as set out in the Summary section below.

Summary

In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate. There are circumstances where the nature of the project justifies exclusion from the formula (i.e. an exogenous factor). However, the lumpiness of the expenditures is not, in itself, sufficient criteria. As previously stated, the Panel expects the utilities to manage their capital projects in a manner that is consistent with the spending envelope provided by the PBR plan. Further, there may be circumstances where capital that is not exogenous should be excluded from the formula. The threshold for such exclusion should be based on a dollar-amount**.**

The Panel invites further submissions on this matter, specifically on the issues set out below:

1. What exogenous criteria should be established for excluded capital?
2. In addition to a capital exogenous factor, is a materiality threshold required?
3. If a materiality threshold is appropriate, at what level should it be set in order to realize the full benefits of PBR? Given your responses to 1, 2 and 3, what should the base capital be set for FEI and FBC for 2016?
4. Is a cumulative dead-band of 15% over two years sufficient to protect both ratepayers and shareholders?
5. What reporting procedures should be in place to allow parties sufficient time to review proposed capital spending?
6. Should the CPCN threshold be raised to match or exceed the PBR formula materiality threshold?

Submissions should be received in accordance with the following timetable:

Submission from Fortis	December 31, 2014
Submissions from Interveners	April 30, 2015
Reply Submission from Fortis	June 30, 2015

The Commission will provide further direction concerning process following Fortis' reply.

Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.

In making this determination, we are mindful of the concerns of Interveners and are of the view that a two year cumulative dead band is appropriate and considers 15 percent over or underspend an appropriate setting for a two year cumulative dead-band. Accordingly, the Commission Panel directs, in addition to the one year 10 percent dead-band previously approved, a two year cumulative 15 percent dead-band for all Fortis' formulaic capital spending.

Other Issues

a. The Impact of Capital on O&M

To the extent that a project results in a reduction of maintenance expenditures, the utility will have the opportunity to underspend its maintenance spending envelope. The Panel recommends that, if capital associated with a particular CPCN is excluded from the formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made.

b. AMI Capital

With regard to CEC's concern about the benefits of the AMI project not being captured, the Panel does not agree. Table B6-5 in the Application and the spreadsheet at Attachment 1.1 of Panel IR 1.1 show O&M formula spending reduced by over $7.5 million to account for AMI benefits over the PBR period.

2.2.6 Mid-Term Review and Annual Review Process

The purpose and content of the Annual Review was a significant point of contention in the hearing. Fortis envisaged the Annual Review process as primarily an information sharing forum similar in scope and process to Annual Reviews held in previous PBRs (FEI Exhibit B-1, pp. 78–79; FBC Exhibit B-1, pp. 71–72). A number of interveners saw the Annual Review as having a broader scope and dealing with a variety of issues. Fortis submits that a clear definition of the purpose and scope of the Annual Review is required if the PBR is to operate successfully. (Fortis PBR Reply, p. 54)

The Mid-Term Review is proposed by the Companies as an opportunity for stakeholders to review the outcomes of the PBR and suggest adjustments to certain planned parameters if required. The Mid-Term Review will form part of the third Annual Review, acting as a "checkpoint" that allows parties to address discrete flaws in what is otherwise a workable PBR plan. CEC was the only intervener to raise issues specific to the Mid-Term Review. (FBC Exhibit B-1, pp. 69, 70; FEI Exhibit B-1, pp. 76–77)

Unlike past PBRs, which were put in place following a negotiated settlement process, under this PBR the Annual and Mid-Term Review processes are taking place after a hearing process where stakeholders expressed serious reservations with the applied for PBR, with some parties opposing the use of a PBR altogether. In this environment, the Panel considers there is a need for the review processes to be more extensive, at least in the first few years, in order to build trust between the Companies and stakeholders and to ensure that the PBR process is working fairly and effectively.

Fortis' Annual Review Proposal

Fortis envisages the Annual Review to be identical to the process that was undertaken in previous PBRs. This process would consist of a workshop, one round of information requests from the Commission and interveners, letters of comment, and a Commission determination of rates. Fortis states that as part of the Annual Review process, the following actions will occur:

- The Companies will present the current year's projections and the upcoming year's forecasts for a number of measures;
- Flow-through items will be trued-up to actuals for the prior year; and
- Inputs in the PBR formula, such as inflation and customer growth will be re-forecast.

(FEI Exhibit B-1 p. 79; FBC Exhibit B-1, pp. 71–72; Fortis PBR Final Argument, p. 59)

Intervener Submissions

The issues or concerns raised by interveners with respect to the Annual Review include:

- The inadequacy of treatment of SQI's (COPE Final Argument p. 51). If the SQI's targets are not achieved there should be the opportunity for interveners to make submissions that the incentive earnings of the Company are reduced (BCPSO PBR Final Argument, p. 20);
- The reviews are too limited. There should be an opportunity to review PBR performance and to make improvements to the PBR Plan, under Commission oversight. There should be a greater opportunity for stakeholders to get information and pursue any areas that are deemed necessary to ensure the ongoing applicability of the PBR formula. (CEC PBR Final Argument, pp. 162–163);
- There should be a review of efficiency proposals at the Annual Review (CEC PBR Final Argument p. 26);
- The Annual Review process will be much more expensive than estimated by Fortis. The regulatory efficiencies expected by Fortis will not be achieved. (CEC PBR Final Argument, pp. 11–12; BCPSO PBR Final Argument, para. 13); and
- Fortis should be required to disclose all exogenous events that result in benefits to the ratepayer at the Annual Review (CEC PBR Final Argument, p. 158).

Fortis Reply

The Companies responded to these criticisms by stating that:

- If there was concern about a deterioration of service that was seen to be due to the fault of the Company, there would be significant discussion at the Annual Review, potentially leading to a decision by the Commission (T5:1051).
- While the review of the cost of service will not be as detailed as in a revenue requirements application, since controllable costs are largely formula driven, the Annual Review will provide more frequent reporting than would normally exist under Cost of Service regulation (Fortis PBR Final Argument, p. 59).
- One of the key benefits of the PBR will be eliminated if Fortis is required at each Annual Review to provide a detailed justification of individual efficiencies achieved in the prior year (Fortis PBR Reply, p. 54).
- The regulatory cost savings under past PBR plans provide an evidentiary basis to conclude there will be direct cost savings under the proposed PBR plan. Given that the most contentious aspects of the Companies' revenue requirements will be determined by the formula, it is logical to expect both direct and indirect savings. Intervener arguments on regulatory cost are founded on errors or flawed logic (Fortis PBR Reply, pp. 15–16).

Commission Determination

The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended. This will address some of the concerns expressed by CEC with respect to the consensus requirement to bring forward issues and with respect to the timing of airing concerns related to PBR elements. The Panel finds that the enhanced ability to assess the PBR Plan at Annual Reviews also addresses the concern expressed about the symmetry of the financial distress criterion. If the PBR plan is seen by any stakeholder as inducing financial distress, the issue may be raised at the Annual Reviews and if not resolved, brought to the Commission for resolution.

In what follows, the Commission Panel sets out the activities to be undertaken in all Annual Reviews before describing topics to be covered in the first Annual Review.

All Annual Reviews

The Commission directs that the Annual Review process include the following:

1. **Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.**

2. **Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below:**

    a. **Customer growth, volumes and revenues;**

    b. **Year-end and average customers, and other cost driver information including inflation;**

    c. **Expenses (determined by the PBR formula plus flow-through items);**

    d. **Capital expenditures (as determined by the PBR formula plus flow-through items);**

    e. **Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;**

    f. **Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and**

    g. **Any proposals for funding of incremental resources in support of customer service and load growth initiatives.**

3. **Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives (see Section 2.3.2 for a more detailed discussion of the ECM).**

4. **Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers (see Section 2.2.4 for details).**

5. **Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service (see Section 2.3.3.2 for details).**

6. **Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.**

7. **Assess and make recommendations to the Commission on the scope for future Annual Reviews.**

Given this more comprehensive Annual Review, the Panel is of the view that a Mid Term Review will not be required. **Accordingly, Fortis' request for a Mid-Term Review is denied.**

2.2.6.1 Unique First Annual Review Requirements

The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.

3.0 MAKING PBR WORK

3.1 Key Issues

3.1.1 Load Forecasts

As part of FBC's previous revenue requirements applications (RRA) review process, the Load Forecast Technical Committee (LFTC), consisting of representatives from FBC, interested interveners and Commission staff, was established to review and make recommendations on FBC's load forecasting methods and results. A report was filed by the LFTC which outlined the methodology to be undertaken by FBC in developing its 2014 Load Forecast.

In its current Application, FBC explains that its sales revenues are a function of both the load and the applicable rate at the time the energy is consumed. FBC's revenues are expected to increase slightly over the PBR period based on its total load forecast provided on page 80 of its Application and detailed in Appendix E2 of Exhibit B-1-1, and shown below

Table 3.1 FBC's Load Forecast

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Before-Savings	3,351	3,416	3,369	3,447	3,422	3,520	3,570	3,607	3,642	3,675	3,715
After-Savings						3,496	3,519	3,537	3,554	3,572	3,596
After-Savings Growth	-1.9%	1.9%	-1.4%	2.3%	-0.7%	2.2%	0.7%	0.5%	0.5%	0.5%	0.6%

(Total load forecast shown in GWh)

FBC proposes that load will be forecast each year at the Annual Review and then considered along with the revenue requirement to establish rates for the forecast year (Exhibit B-1, p. 62). BCPSO observes that since load growth will be updated during each Annual Review, the emphasis should be on the 2014 load forecast for 2014 rates (Exhibit B-1, p. 71; BCPSO FBC Non PBR Final Argument, p. 8).

FBC also states that its acquisition of the distribution assets owned by the City of Kelowna on March 31, 2013, added approximately 14,500 customers to the FBC system; approximately 1,500 commercial, 9 industrial, and the remainder residential. The current customers load mix for City of Kelowna is approximately 45.4 percent, 32.6 percent and 22.0 percent for residential, commercial and industrial loads, respectively.

Due to the unavailability of sufficient historical load information prior to the transaction, FBC indicates that it is not possible to ensure that the same forecast methods applied to the existing FBC load classes would also be reasonable to apply to the City of Kelowna load classes. Therefore, the City of Kelowna load is forecast as a whole, and then allocated to the three load classes according to the proportions identified above (Exhibit B-1, pp. 81–82).

BCPSO, the only intervener that commented on FBC's 2014 load forecast, claims that FBC's calculation of rate-driven savings in 2014 has several flaws and submits that "FBC has just started to recognize rate-driven savings in its load forecasts. Clearly more consideration needs to be given as to how to appropriately estimate such savings given its current load forecast methodology." (BCPSO, FBC Non PBR Final Argument, pp. 9–10) However, BCPSO makes no specific recommendations or adjustments to FBC's Load Forecast for 2014.

Commission Determination

The Commission Panel accepts FBC's load forecasts and agrees that the methodology used by FBC conforms to the recommendations set by the LFTC and outlined in its report dated November 25, 2011.

The Panel notes that that City of Kelowna integration did not have any significant impact as this load was previously captured under the Wholesale customers load forecast, whereas now the load is split across the residential, commercial and industrial customer classes. The Panel accepts this reclassification; however, we are unclear as to why FBC is unable to obtain sufficient historic load information from the City of Kelowna. **FBC is directed to provide an explanation at the next Annual Review as to why this information for past years is unavailable.**

Concerning the issue raised by BCPSO on FBC's rate-driven savings in 2014, the Panel agrees with FBC. This results in a relatively small impact (a point acknowledged by BCPSO) as rate-driven savings are only 0.27 percent of the total gross forecast load (FBC Non PBR Final Argument, p. 26; BCPSO Non PBR Final Argument, p. 9). The Panel recommends that the parties bring forward any material load forecasting issues as part of future Annual Reviews during the PBR period.

3.1.2 Determining the Base O&M

As a general approach, FBC proposes that the Commission rely upon the 2013 Approved O&M expenditures as a starting point for determining the PBR opening O&M. These would be adjusted by specific changes which have occurred since these amounts were approved in the FBC 2012–2013 RRA Decision.[14] In FBC's Application, the 2013 Approved O&M combined with specific adjustments proposed by FBC serve as a basis for a revised starting point for the PBR. FBC refers to this as the 2013 Base O&M. As a starting point, the methodology for determining the 2013 Base O&M will be considered.

[14] In the Matter of an Application by FBC regarding its 2012–2013 RRA & Integrated System Plan, Decision dated August 15, 2012 [herein referred to as the FBC 2012–2013 RRA Decision]

3.1.2.1 Methodology for Base O&M Determination

As noted, FBC has used the 2013 Approved O&M amount as the starting point. This has been chosen as an appropriate starting point because it results from a full review in an oral public hearing. To this, Fortis makes three types of adjustments. These are as follows:

- Adjustments that recognize the sustainable savings of $452,000 realized in 2012 and that will carry over to future years.
- Adjustments reflecting the rebasing of 2013 Approved to the expected 2013 Actual for items currently captured in deferral accounts that are considered non-controllable. These total $3.238 million and include $900,000 for Mandatory Reliability Standards (MRS), $180,000 related to the annualized impact of the reinstatement of PST and $2.158 million for Pension and Other Post-Employment Benefits (OPEB).
- Other O&M expenses and reductions allowing for delivery of cost-effective service to customers. These include a reduction of $909,000 in the Trail Office Lease Payments due to the purchase by FBC and an increase of $350,000 for recurring maintenance to FBC's generating units.

FBC states that the purpose of these adjustments is to provide an appropriate starting point for the PBR period and the approach it takes is reasonable and common practice where revenue requirements have been recently assessed. As noted in Table 3.2 below, the net effect of these adjustments is to increase the Base O&M from $57.621 million in the 2013 Decision to a new base of $59.848 million. (FBC Exhibit B-1, pp. 50–51)

Table 3.2 2013 Base O&M Calculation

		($ thousands)	
1	**2013 Decision**		**57,621**
2			
3	Net Sustainable Savings		(452)
4			
5	2013 Adjustments		
6	Mandatory Reliability Standards	900	
7	Provincial Sales Tax	180	
8	Pension/OPEB (O&M Portion)	2,158	3,238
9			
10	Incremental O&M		
11	Trail Office Lease	(909)	
12	Generation Maintenance	350	(559)
13			
14	**2013 Base O&M**		**59,848**

(Source: FBC Exhibit B-1, p. 51)

Intervener Submissions

CEC is not in agreement with the methodology proposed by FBC. It does not consider the 2013 Approved O&M, with adjustments, to be an appropriate starting place because the 2013 O&M projection is not supported by any significant amount of actual 2013 history. It describes the 2013 O&M approved amount as “a forecast developed in 2011, or before, as part of the FBC 2012–2013 Revenue Requirements Application process.” Further, when approved, the Commission had no intention of using it as a basis for a PBR process.

CEC’s position is that considerable attention should be paid to 2012 Actual O&M costs in the development of the 2013 O&M Base amount pointing out that it is the latest, most accurate representation of business in the specific timeframe. It submits that in creating the 2013 O&M Base, care must be taken to remove all non-recurring cost items. Relying on the FBC response to BCUC IR 1.95.1, CEC observes that actual 2012 expenditures are not materially different from 2011 and the cost per customer is similar. It also points out that the 2012 Approved cost per customer

($483) is substantially higher than the 2013 Approved ($463) and higher than that of 2011 ($470). (CEC FBC Non PBR Final Argument, Base O&M, pp. 3–6)

BCPSO submits that relying upon the 2013 Approved O&M as a base for PBR is a reasonable approach noting that the 2013 Approved O&M per customer is lower than the 2012 Approved. An alternative to this would be to use the actual results from 2013 as they would constitute the best available evidence on which to base O&M on a forward-looking basis. (BCPSO Non PBR Final Argument, p. 6)

ICG is not opposed to using FBC's 2013 Approved O&M expenses as a base but asserts this number should be reduced to ensure reasonable targets under the PBR Plan (ICG Final Argument, p. 21).

FBC Reply

FBC disagrees with using either 2012 actual as proposed by CEC or 2013 Actual O&M expenditures as proposed by BCPSO. In FBC's view, it is important to use the 2013 Approved O&M as a starting point because this amount received Commission approval in a recent regulatory proceeding. In addition, FBC's approach is endorsed by B&V and is in alignment with the method used in the 2007 PBR Plan. Further, it disagrees with CEC's critique concerning the Commission's intentions when it last examined and approved O&M expenditures. FBC states that it "does not alter the fact that 2013 Approved O&M represents the most recent Commission approved O&M figure for the Company, or the fact that the figure was determined following a thorough regulatory process." (FBC Non PBR Reply, p. 3)

Concerning CEC's analysis and submissions on the comparison of 2011, 2012 Actual, and 2013 projected O&M costs and resultant per customer costs, FBC argues that it ignores the reason why 2012 Actual expenditures were lower than both 2012 and 2013 Approved expenditures and not sustainable into the future. FBC states that the lower 2012 actual costs were a result of the August timing of the 2012–2013 RRA Decision, which was released three quarters (actually two-thirds) of the way through 2012. This resulted in savings which are not sustainable. (FBC Non PBR Reply, p. 4)

FBC also has issues with the use of 2013 Actual for the base as proposed by BCPSO pointing out that the 2013 Actual O&M has not been considered as a figure in the hearing and is not on the record. The Panel notes that this is no longer true as it is now on the record as part of the response to the Commission Panel IR. In any case, FBC states that relying on 2013 Actual O&M would not be a simple change to make as it "could not simply be substituted for 2013 Approved O&M. Instead, each of the proposed adjustments would need to be re-analysed and modified for 2013 Actual O&M to be used as a starting point." (FBC Non PBR Reply, pp. 1–5)

Commission Determination

The Commission Panel determines that an appropriate starting point for the development of the PBR O&M Base is the 2013 Approved O&M. We agree with FBC that this figure has been scrutinized in a recent regulatory proceeding and accept that this is common regulatory practice. Reliance on actual O&M amounts for 2012 would be inappropriate given the timing of the FBC 2012–2013 RRA Decision and the Company's explanation that it postponed expenditures scheduled for this period while it awaited the results of the Commission's review. Equally, a reliance on 2013 Actual O&M expenditures presents its own set of challenges due to the labour disruption which would require its own set of adjustments and a limited evidentiary record on which to base them.

In the following sections, we consider the evidence, address arguments raised by the parties and determine the appropriate PBR Opening O&M Base for FBC.

3.1.2.2 Determining the FBC PBR Opening O&M Base

As outlined previously, FBC uses the 2013 Approved O&M of $57.621 million as a starting point for the O&M formula. It then makes a number of adjustments, as listed in the previous section, which result in a 2013 Base O&M of $59.848 million. This is the figure to which FBC proposes to apply the approved I-X formula during the PBR term.

Over the course of the proceeding, a number of issues related to O&M have been raised by interveners. These include labour costs and benefits, regulatory efficiencies, the impact of AMI and exclusions from the O&M formula. The Company addressed these as follows:

a. Labour Costs and Benefits

The Company applies the same approach to compensation and benefits for all of its employees. This includes a total compensation package aimed at the median level of a peer group of companies. The only change in employee compensation packages planned over the PBR period is to transition its executive employees to a new health and welfare benefits plan.

FBC was involved in a labour disruption of the International Brotherhood of Electrical Workers (IBEW) but, in its assessment, there was no impact on a net basis to O&M expenses that resulted from this. The Company explained that labour costs savings were offset by cost increases in other areas as a result of the disruption. Many of these related to lower labour capital loadings due to delayed capital expenditures. The additional costs included:

- An increase to the O&M portion of benefit costs. While total benefit costs remained the same, less was loaded into capital due to delayed capital expenditures.
- Higher overtime costs for management and exempt employees.
- An increase to O&M as a result of salaries not being paid to IBEW staff, which meant that only 40 percent of salaries could be considered avoided capital rather than the traditional 60 percent allocation.
- A greater portion of labour and vehicle costs were charged to 2013 O&M expense not capital. This results from capital expenses being carried over from 2013 to future years.

(FBC Non PBR Final Argument, pp. 18–19)

FBC submits that the impact of the labour disruption on O&M expense is not reflective of its ongoing operations and does not impact 2013 Base O&M Expense. Accordingly, it does not necessitate adjustment of the O&M formula during PBR. (FBC Non PBR Final Argument, pp. 18–23)

b. Regulatory Efficiencies

FBC argues that expected savings due to the change to PBR do not warrant a reduction from the 2013 Base O&M. FBC argues that it has been regulated under various PBR plans for much of the period since 1996. PBR has become a more normal state and the staff contingent has remained constant during PBR and non PBR periods. Additionally, looking forward, the regulatory department will continue with annual reviews, on-going regulatory work for Certificate of Public Convenience and Necessity (CPCN) applications, cost of capital matters, rate design and other regulatory work. (FBC Non PBR Final Argument, pp. 20–21)

c. Impact of Advanced Metering Infrastructure Approval

FBC notes that the Application was prepared on the basis that the Advanced Metering Infrastructure (AMI) Project Application would be approved and in the event it was not, the PBR Application would be amended. The Application is consistent with approval of the project and therefore needs no adjustment. (FBC Non PBR Final Argument, p. 21)

d. Exclusions from the O&M Formula

O&M expenses related to pension and OPEB, insurance expense and the AMI project are to be tracked outside of the PBR formula. FBC points out that the AMI project will be subject to expenditures and savings which will be highly variable during the implementation phase. By tracking these costs outside of PBR any savings will flow directly to the ratepayer. FBC also addresses insurance expenses and indicates that, as reflected in answers to IRs, it would not object to excluding only insurance premiums from the Base O&M. This would be consistent with the handling for FEI and would involve increasing the 2013 Base O&M by $274,000 to account for the First and Third Party Liability Expense. (FBC Non PBR Final Argument, pp. 21–23)

Table 3.3, as provided by FBC provides a historical context for O&M actual expenditures and outlines the 2012 and 2013 Approved O&M and a projection for 2013 for each of its departmental work areas. In addition, along the bottom of this table, information related to customer growth and resultant O&M per customer is included. (Exhibit B-7, BCUC 1.95.1)

Table 3.3 Historical O&M Per Customer

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
				($000's)				
Generation	$ 1,894	$ 2,152	$ 2,217	$ 2,399	$ 2,331	$ 2,282	$ 2,556	$ 2,492
Operations	$ 14,924	15,057	14,892	18,604	19,730	19,920	20,938	20,816
Customer Service	$ 6,272	5,835	5,975	6,398	6,766	6,624	7,510	7,541
Communications & External Relations	$ 1,079	1,150	1,639	1,469	1,244	1,431	1,440	1,469
Energy Supply	$ 546	739	827	893	986	1,069	1,124	1,124
Information Technology	$ 2,834	2,938	2,929	2,903	2,925	2,841	2,988	2,974
Engineering	$ 1,184	1,143	1,242	2,363	2,615	2,701	2,822	2,791
Operations Support	$ 1,651	1,028	993	1,315	1,240	1,223	1,205	1,252
Facilities	$ 2,834	3,537	3,700	3,720	3,596	3,685	3,389	3,466
Environment, Health & Safety	$ 616	645	727	867	894	925	953	953
Finance & Regulatory	$ 3,631	3,624	3,576	3,882	3,823	4,392	4,080	4,271
Human Resources	$ 1,540	1,558	1,638	1,747	1,816	1,840	1,874	1,874
Governance	$ 2,006	2,066	2,284	2,031	2,134	1,792	2,490	2,373
Corporate	$ 3,716	4,545	3,510	4,484	3,444	4,118	3,800	4,225
Advanced Metering Infrastructure	$ -	-	-	-	-	-	-	-
Total O&M	**$ 44,725**	**$ 46,017**	**$ 46,149**	**$ 53,075**	**$ 53,544**	**$ 54,843**	**$ 57,169**	**$ 57,621**
Customers	**108,722**	**110,286**	**111,552**	**112,756**	**113,587**	**113,588**	**121,566**	**124,581**
O&M per Customer	**$ 411**	**$ 417**	**$ 414**	**$ 471**	**$ 471**	**$ 483**	**$ 470**	**$ 463**

(Source: FBC Exhibit B-7, BCUC 1.95.1)

In response to Commission Panel IR 1.3.1, FBC has further updated this information by providing the 2013 Actual O&M expenditures in Table 3.4 that follows. Tables 3.2 and 3.3 provide further context to the discussion and the submissions of the parties that follow.

Table 3.4 2013 O&M

	2013 Approved	2013 Projection	2013 Actual
		($000s)	
Generation	$ 2,492	$ 2,556	$ 2,513
Operations	20,816	20,938	20,886
Customer Service	7,541	7,510	7,631
External Relations	1,469	1,440	1,426
Energy Supply	1,124	1,124	1,083
Information Technology	2,974	2,988	2,948
Engineering	2,791	2,822	2,737
Operations Support	1,252	1,205	1,252
Facilities	3,466	3,389	3,493
Environment, Health & Safety	953	953	877
Finance & Regulatory	4,271	4,080	3,908
Human Resources	1,874	1,874	1,835
Governance	2,373	2,490	2,400
Corporate	4,225	3,800	3,706
Total O&M Expense	**$ 57,621**	**$ 57,169**	**$ 56,696**
2013 O&M Adjustment	-	-	576
Total O&M	**$ 57,621**	**$ 57,169**	**$ 57,272**

(Source: FBC Exhibit B-53, Panel 1.3.1)

Intervener Submissions

CEC has proposed that FBC's PBR O&M Base be reduced by $755,000 to $59.093 million based on an analysis of FBC O&M Departments. On a departmental basis CEC is recommending the following:

a. Generation…reduce by $113,000;

b. Operations…reduce by $312,000;

c. Customer Service…reduce by $152,000;

d. Information Technology…reduce by $14,000;

e. Engineering and Project Management…reduce by $31,000;

f. Finance and Regulatory…reduce by $100,000; and

g. Environmental Health and Safety…reduce by $31,000.

The reasons for these reductions vary by department but fall into the following broad categories: unexplained expenses added to 2013 Approved O&M, under or over expenditures to either 2012 or 2013 amounts, expected savings flowing from reduced customer counts, and expected savings due to CEC's interpretation of employee counts and the dollar amounts related to them.

CEC also takes issue with the FBC proposal to add $350,000 for incremental generation maintenance which FBC states are for major unit inspections. CEC submits that the cost of inspections will vary significantly because of the various sizes, ages and conditions of plant units. It considers these major unit inspections to be "non-controllable" and should be tracked outside of the PBR.

CEC also submits that the flow-through process should be expanded to include "the expenditures required to complete the 'major' O&M inspections required to comply with regulations and/or which must be completed to insure assets are maintained at industry standards." CEC classifies a single inspection costing more than $50,000 as "major." It argues that these major inspections are uncontrollable because they cannot be avoided and the timing of them is out of the Company's control as either regulations or industry standards drive the timing of activities. Its position is that the cost of a major inspection is driven by the nature of the inspection and the asset being inspected. Because of this, it is reasonable to expect significant variance among inspections and the actual cost could vary significantly from the amount embedded in the PBR Base amount. CEC also submits that a further reason to track these costs outside of the PBR Base is because it is inappropriate to tie them to the "Average Customer element within the PBR formula, since the cost of major inspections are not in any way influenced by the total number of customers." (CEC FBC Non PBR Final Argument, Base O&M, pp. 5–6)

BCPSO asserts that FBC's "sustained savings" are not based on savings resulting from efficiency initiatives but represent the cumulative total of corporate departmental variances between approved and projected O&M expense, some of which were positive and some negative. BCPSO commented on FBC's answer to BCUC IR 1.1.1 stating that a reduction of $587 thousand in explainable variances was made while increased costs totalling $135 thousand across a number of departments had no explanation. BCPSO argues that the full amount of $587 thousand should be considered sustained savings due to the lack of explanation for the increases. In addition, BCPSO makes the following comments:

- FBC's proposed adjustments for MRS, re-instatement of PST and Pension/OPEB is reasonable as is the adjustment for the Trail lease and generation maintenance.
- The potential to include first and third party liability insurance in the formula, as suggested by Fortis in its response to BCUC IR 2.59.1, is reasonable. However, the proposed $274,000 increase to the PBR O&M base is not reasonable. It should be based on 2013 not a 2014 projection. BCPSO suggests that $106,000 is a more appropriate amount for the first and third party liability expenses. It did not address FBC's reasons for the higher forecast.
- BCPSO agrees with FBC's proposal to set up the 2013 deferred O&M account to acknowledge FBC's scheduled and necessary maintenance work from 2013, which will be required and performed in 2014, in addition to the scheduled 2014 programs (BCPSO FBC Non-PBR Final Submission, para. 1.1).

(BCPSO FBC Non PBR Final Argument, pp. 5–7)

ICG cites the 15 percent increase in expenses from 2010 to 2011 and the 12 percent increase from 2012 to 2013 that will be embedded into rates in the event the base is established using 2013 approved O&M expenses. ICG proposes to reduce the applied for Base O&M expenditures by 20 percent given the absence of evidence regarding operating efficiencies and its concern as to fairness to customers. (ICG Final Argument, p. 21)

<u>FBC Reply</u>

Fortis is unclear as to how BCPSO arrived at the $587 thousand and $135 thousand it has incorporated into its submission. The reference relied upon by BCPSO lists different numbers than those stated by BCPSO and FBC assumes a calculation error was made. It believes what should have been proposed is modifying the sustainable savings from the proposed $452,000 to $559,000. FBC makes no further comment other than to state it disagrees with BCPSO's recommended savings adjustment regardless of the number relied upon. (FBC Non PBR Reply, p. 7)

FBC takes issue with the detailed approach taken by CEC to establish a base. Incremental costs and savings are considered by FBC "to be sustainable going forward, regardless of whether or not it may be attributed to one single item. As all of the savings and costs are expected to continue to be realized during the PBR Term, they are appropriately embedded into the 2013 Base O&M." Fortis also points out that a fundamental PBR Plan premise is that O&M expenses are to be determined on an aggregate level across all departments. It further states that to incorporate those portions of the sustainable savings adjustment that reduces Base O&M while excluding those that increase Base O&M is inconsistent and illogical. Fortis relies upon this explanation to deal with those costs which it has added without further explanation. These include $122 thousand for Operations, $14 thousand for Information Technology and $31 thousand for Engineering Services and Project Management. (FBC Non PBR Reply, pp. 9–10)

FBC makes a number of submissions concerning CEC's department-specific submissions. With regard to departmental under spending, FBC considers the aggregate level of expenses as being more important than individual department expenses. Using the Generation Department as an example, FBC points out that one year's lower projected savings for non-routine activities would skew the net effect of overall expenditures. It takes a similar position with the $190,000 in savings from Operations it considers to be non-sustainable. FBC further states that CEC's proposed reduction of $152,000 in Customer Service related to the reduced number of customers is likewise inappropriate, as the costs for the department did not decline commensurately with a decline in customers. Moreover, call volumes were higher than expected which resulted in higher labour costs. Concerning savings related to employee counts in the Finance and Regulatory department, FBC provides a detailed explanation of its labour issues and the dollar amount attributable to them, stating that the position taken by CEC is misinformed. (FBC Non PBR Reply, pp. 11–18)

The information provided by FBC in response to the Panel IR confirmed the 2013 Actual O&M expense of $56.272 million, which is $473,000 below the 2013 projection. In response to Commission Panel IR 1.3.1, FBC states that an adjustment of $576,000 had been made to capture O&M expenses that were planned for 2013 but were delayed due to the labour disruption and will be spent in 2014. This amount is lower than the $800,000 that was originally estimated. FBC's position is that these amounts would have been spent had it not been for the labour disruption and should be incorporated into any comparison. If this is taken into consideration, the 2013 Actual O&M is $103,000 higher than the 2013 Projected O&M and $349,000 lower than the 2013 Approved O&M. FBC further explains in response to Panel IR 1.3.2 that the 2013 Actual O&M, even in consideration of the adjustment for 2013's delayed O&M, is not reflective of typical operating conditions as activities of supporting departments were impacted by the labour disruption during nearly half of the year. (Exhibit B-53, Panel 1.3.1–1.3.2)

With respect to CEC's recommendation to exclude dam inspections over $50,000 to be processed as a flow-through, FBC disagrees. It submits that CEC has provided no evidence suggesting that the $350,000 amount budgeted is inaccurate or that the cost per year will fluctuate. The costs have been determined based on FBC's experience and knowledge and "are, to a certain extent, controllable in that they are not unforeseen, incremental expenses." FBC states that a 15-year inspection schedule which will be guided by condition, risk and operational priority will allow the company to prioritize maintenance. FBC also points out that 11 of its 15 generating units have received recent upgrades and the condition of the various units is relatively consistent. (FBC Non PBR Reply, pp. 21–22)

Commission Determination

The range of differences among most of the parties with respect to the proposed PBR Opening O&M Base is not large. CEC has proposed that FBC reduce its PBR Opening O&M Base by $755,000 or approximately 1.2 percent and BCPSO has proposed a reduction of $135,000 or 0.2 percent.

The one exception to this is ICG, who takes the position that the PBR Opening O&M Base should be reduced by 20 percent because of FBC's lack of evidence regarding operating efficiencies and concern as to fairness to customers. ICG provided no evidence in support of this, other than pointing out that O&M has increased substantially in the 2010–2011 and 2012–2013 time periods. Given the lack of ICG's analysis and evidence supporting how the 20 percent figure was arrived at, the Commission Panel places no weight on the ICG submissions in this regard.

Prior to considering any of the recommended adjustments to the FBC 2013 Base O&M proposal in the following sections, the Panel addresses a number of issues which have a bearing on O&M in this proceeding.

Labour Disruption and Impact of PBR on the Regulatory Department

The Commission Panel acknowledges that the lengthy labour disruption has been a factor that has had a significant impact on 2013 O&M expenses and, as a result, it is difficult to draw too many conclusions from 2013 O&M actual expenditures. However, the Panel agrees with FBC's proposed 2013 deferred O&M expense account of approximately $576 thousand, as at December 31, 2013 (Exhibit B-53, Panel 3.1). **In accordance with FBC's proposed methodology as outlined in BCUC IR 2.90.13, the Panel approves the deferral account and directs that these deferred expenses be treated outside of Base O&M.**

The Panel also acknowledges that in spite of a PBR there will remain a need for its regulatory department to handle ongoing regulatory activities. FBC has spent much of its recent history under PBR and when not under PBR there were no additional staff positions added. Therefore, the Commission Panel accepts the move back to PBR does not warrant a reduction to the 2013 Base O&M to account for the labour disruption or the impact of PBR on the regulatory department.

Tracking Pension and OPEB, the AMI Project and Insurance Expenses Outside PBR

FBC makes submissions with respect to pension and OPEB, insurance expense and the AMI project being tracked outside of the O&M formula due to potential variability. None of the Interveners object to this proposal in principle. However, BCPSO raises concerns as to FBC's calculations of the amount to be excluded if it were only insurance premiums that were excluded from base costs and first and third party liability expenses were not flowed-through.

The Panel has previously determined that only the premium portion of insurance expenses is flowed-through (see Section 2.2.5). In this event, FBC proposes an increase to the 2013 Base O&M of $274,000 which is the 2014 Forecast for First & Third Party Liability Expense.

Table 2.17 on page 89 of Exhibit B-24 shows the FBC Insurance Expense and the projected cost for 2013 and the 2014 forecast for First and Third Party claims is as follows:

(i) Fluctuation in the number and significance of claims;

(ii) Increase in the Company's customer base by 13 percent due to the acquisition of the City of Kelowna's assets;

(iii) Increase in third party adjusting fees by 20 percent in 2013;

(iv) The potential for liability deductibles to increase.

(Exhibit B-24, BCUC 2.59.2.1)

The Panel agrees with BCPSO that FBC's proposed increase to the Base O&M to include the 2014 forecast for first and third party liability expenses is not consistent with the method with which FBC has determined its other Base O&M expenses. Further, the Panel is not persuaded that the substantial increase in first and third party liability insurance from the projected $106,000 in 2013 to the forecast $274,000 in 2014 is justified. A 13 percent increase in customer base due to the City of Kelowna acquisition and a 20 percent increase in third party adjusting fees do not support a change of this magnitude. In addition, FBC provided no historical information to support this increase based on fluctuation in the number and significance of claims (Exhibit B-24, BCUC 2.59.2.1).

The Panel therefore finds it more appropriate to base the Insurance costs on FBC's 2013 Projection of $106,000 with further adjustments to reflect the impact of the increase to FBC's customer base resulting from the City of Kelowna acquisition and the increase in third party adjusting fees. The Panel has utilized the percentage increases stated by FBC in its response to BCUC IR 2.59.2.1 and has applied an approximately 33 percent increase to the 2013 Projection for First & Third Party Liability Insurance and has thus arrived at a 2013 Base O&M adjustment of $140,000.

Accordingly, the Commission Panel determines that a more appropriate addition to the PBR Opening O&M Base to account for first and third party liability expenses is $140,000.

The Commission Panel accepts the FBC proposal, which allows for pension and OPEB, insurance expense premiums (with the exception of first and third party liability insurance expense), and AMI project costs to be tracked outside of the formula. **The Panel directs that these be excluded from the calculation of the earnings for the purpose of the ESM.**

Major Generation Unit Inspections

Concerning the handling of Major Generation Unit Inspections, the Commission Panel is not persuaded that a case has been made to remove them from the Base O&M at this time.
FBC provides assurances that the $350,000 it proposes is reflective of its experience and knowledge in this area. The Company also provides assurances that there is relative consistency in the condition of most of the generating facilities with 11 units having been recently upgraded and state that their schedule will be guided by condition risk and operational priority. **Given the background and assurances provided by FBC, the Commission Panel finds that the proposal to include the $350,000 within the Base O&M is reasonable and is not persuaded there is a need to make it a flow through item at this time.** However, in consideration of the concerns raised and the magnitude of the estimate, actual expenditures should be monitored through the Annual Review process. With respect to tying a growth factor to Major Unit Inspections, we are in agreement with CEC. However, this is one of many costs and removing this item from the approved formula calculation will only serve to create confusion. The Panel in Section 2.2.6 outlined its concerns with the Growth Factor proposal made by Fortis and has directed that this be reviewed at the first Annual Review meeting.

Adjustments to PBR Opening O&M Base

The Panel considers the PBR Opening O&M Base proposal to favour FBC. The Company has control over the determination of savings it deems to be sustainable and chooses to offset these against departmental over-expenditures in arriving at its sustainable savings adjustment. This would be reasonable if there was a justification of the additional departmental over-expenditures but this is not the case. This issue was raised by both CEC and BCPSO. CEC has proposed that the sustained savings be increased by $167,000 (from Operations, Engineering and Information Technology) while BCPSO has argued that sustained saving should be increased by $135,000. FBC takes the position that it is inconsistent and illogical to incorporate savings which reduce the base but exclude those that increase it. The Panel does not agree. If costs have exceeded approved amounts they require the same level of scrutiny and explanation as any new costs. This is even more important when determining a base for a PBR with a five-year outlook.

More generally, FBC has taken the position that in a given year it may experience unanticipated higher or lower expenses. In response to Commission Panel IR 1.3.2, the Company refers to vacancies created by staff turnover as an item resulting in temporary savings. It further explains that the offset to this is the potential for unanticipated one-time higher expenses such as those for legal that serve to offset those savings. The Panel is not persuaded that the scenario described by Fortis accurately depicts the situation as it exists with respect to balance. Savings related to unanticipated staff vacancies are a fact of life for every organization as events happen that cannot be anticipated which result in savings while a suitable replacement is found. Where these types of savings will occur departmentally is impossible to predict but the fact that they will occur is predictable and savings will be made within the Company. On the other hand, unanticipated higher expenses do occur but there is no evidence to suggest that these occur with the frequency or magnitude as do savings arising from, for example, staff vacancies. The Fortis response to BCUC IR 3.45.4 may provide some insight. In all but one year between 2003 and 2012 FBC has achieved higher than its approved ROE. The lack of balance between unanticipated savings and unanticipated additional expenditures cannot be quantified in exact terms but may be a factor in FBC's historical ROE performance.

In consideration of these factors, the Commission Panel considers that in addition to other directives elsewhere in this Decision, a downward adjustment in the PBR Opening O&M Base is warranted. The Panel, in its best judgement, directs that in addition to the adjustments proposed by FBC a further reduction of $200,000 be made. This is in addition to any further adjustments to 2013 Base O&M directed in this Decision.

3.1.2.3 Executive Compensation Study and Short-Term Incentive Plan

In the FBC 2012–2013 RRA Decision, the Commission was of the view that FBC's compensation package should be reviewed in its entirety before a determination could be made as to whether it was appropriate. The Commission directed FBC to provide benchmarking information on all elements of its executive compensation in its next RRA.

In this Application, FBC submitted a May 2013 Executive Compensation Review conducted by Hay Group Limited (Hay) on a confidential basis. Subsequently, a redacted version of this review was submitted in response to BCUC IR 1.221.1.1. FBC engaged Hay, its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of more than 250 Canadian Commercial Industrial Companies. The Hay study looked specifically at "*Total Direct Compensation*" which is comprised of base salary, short-term incentives, and long-term incentives. (FBC Exhibit B-7, Attachment 226.1.1, Executive Compensation Benchmarking Study)

The following summarizes the observations from Hay's Executive Compensation Review:

- FBC's target *Total Direct Compensation* is below market median for all roles; however, actual *Total Direct Compensation* is somewhat moderated by the strong actual short-term incentive payouts, which ultimately position most FBC executives close to the market median;
- FBC's executive base salaries are generally positioned around the market median, and the target total is close to median for most roles;
- Actual total cash compensation (excluding long term incentives) is very competitive, with all roles above market median.

(FBC Exhibit B-7, Attachment 226.1.1, Executive Compensation Benchmarking Study, pp. 8–11)

In its study, the Hay Group used its comparable Canadian Commercial Industrial reference group which consisted of 275 different companies. When questioned about the appropriateness of the broad-based comparator group included in the study, FBC stated that this group is appropriate for the following reasons:

- There exists a broad spectrum of commercial and industrial organizations with which FBC competes for executive talent;
- A larger comparator group leads to more stable data year over year;
- These organizations represent a stable, national comparator upon which to base compensation policy.

(Exhibit B-7, BCUC 1.219.1.1)

FBC also filed its 2013 Short-Term Incentive Plan (STIP) targets and explains that there are both corporate and personal objectives to be obtained before STI's are granted. Table 3.5 shows FBC's 2013 corporate targets and weightings:

Table 3.5 FBC's 2013 Corporate Targets and Weightings by Category

The targets and weightings for 2013 are:

Category	Measurement	2012 Results	2013 Targets Minimum 50%	Target 100%	Maximum 150%	Weight
Financial	Regulated Earnings	$48.5	Plan -2% $43.2M	Plan $44.1M	Plan +2% $45.0M	30%
Safety	All Injury Frequency Rate (AIFR)	1.72	Target +10% 1.80	Average of last 3 years 1.64	Target -10% 1.48	10%
	Recordable Vehicle Incidents	22	Target +10% 30	Average of last 3 years 27	Target - 10% 24	10%
Customer	Customer Service Index (CSI)	8.4	8.3	8.5	8.7	12.5%
	System Average Interruption Duration Index (SAIDI)	1.95	Target +5% 2.33	Average of last 3 years 2.22	Target -5% 2.11	12.5%
Regulatory	Regulatory Performance	-	Subjective	Subjective	Subjective	25%
TOTAL						100%

(Source: Exhibit B-7, Attachment 221.1)

FBC explains that the STIP is based on corporate and individual performance objectives and that the corporate objectives have four components: Financial, Safety, Customer and Regulatory. Each component has three measures: threshold (50 percent), target (100 percent) and maximum (150 percent) and the benefits are allocated as follows:

- If performance is below target, the variance from target is prorated between threshold (50 percent) and target (100 percent);

- If performance is above target; the variance is pro-rated between (100 percent) and maximum (150 percent).

The target payout levels and the design of the weightings for the purpose of determining payouts are:

	Weightings		
Position	Individual	Corporate	Target Bonus Level (% of Salary)
President and CEO	20%	80%	50%
Vice Presidents	50%	50%	30 - 40%

(Source: Exhibit B-7, Attachment 221.1)

With respect to the competitiveness of the STIP, the Hay Group makes the following comments:

- Actual total cash [Base Salary + Actual STI] is very competitive, with all FortisBC executives above market median. This is driven by strong actual STI grants as compared to the market, with all actual STIs above the 70th percentile.
- The strong STI rewards driving competitive total cash are largely offset by weak long-term incentive (LTI) compensation, resulting in actual total direct compensation [Actual Total Cash + LTI] generally around market median.

(Exhibit B-7, Attachment 226.1.1)

Table 3.6 provides a review of STI payments as a percentage of salary from a historical perspective.

Table 3.6 Short-Term Incentive Payments to FBC Executives for the Last Five Years

	Actual STI as % of Salary				
	2008	2009	2010	2011	2012
President & CEO	56.94%	60.00%	79.08%	85.00%	76.92%
EVP HR, Customer and Corporate Services	41.86%	45.65%	56.96%	67.62%	60.34%
EVP Network Services, Engineering and Generation	41.86%	45.65%	43.48%	65.74%	60.49%
VP Finance & CEO	44.19%	45.65%	52.17%	63.83%	68.02%
VP Operations Support, Gen Counsel & Corporate Services	49.50%	46.67%	48.00%	54.16%	50.74%
VP Resource Planning	38.64%	45.65%	50.00%	-	-
VP Energy Solutions & External Relations	-	-	46.95%	63.50%	58.94%
VP Energy Supply & Resource Development	-	-	46.36%	59.76%	68.97%
VP Strat Plan, Corporate Development and Regulatory Affairs	-	-	62.79%	63.83%	68.02%
VP Customer Service	-	-	-	-	46.48%

(Source: Exhibit B-7, BCUC 1.221.1.2)

A review of this table shows that there has likely been an increase in STIP in the 2011/2012 years as compared to 2008 or 2009.

Commission Determination

FBC's long-term incentive amounts (i.e. stock options and PSUs) are not recovered from the ratepayer and the Company has provided limited information on this component. Because of this, the Commission Panel focuses on the short-term incentives as a percentage of base salary and total cash compensation.

The three main areas of concern to the Panel are:

- Whether the Hay study comparator group is reasonable;
- Whether the STIP targets will provide benefits to the ratepayers; and
- Whether short-term incentive amounts paid to executives are reasonable.

Hay Study Comparator Group

The Commission Panel accepts that FBC competes for executive talent in the broad spectrum of commercial and industrial organizations. Therefore, FBC's rationale for the choice of the larger, broad-based comparator group is reasonable.

Provision of Benefits to Ratepayers

The Panel has concerns as to whether all of the components of FBC's corporate and individual performance objectives or scorecard provide value to the ratepayer. The Panel notes that the corporate financial objective with the highest weighting, at 30 percent, is regulated earnings. While there is no disagreement as to the importance of a utility being healthy and financially sound financially, the Panel is not persuaded that exceeding its approved ROE is in the interest of ratepayers.

For these reasons, the Panel is not persuaded there is sufficient evidence to support the need for the STIP to be fully funded by the ratepayer. **The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and reduce its O&M Base accordingly.**

Reasonableness of STI Paid to Executives

The evidence regarding executive total direct compensation indicates that the actual STIP is very competitive when compared to the market median. This is confirmed by the Hay Study which states that weakness or shortfall in the competitiveness of long-term compensation is somewhat moderated by the strong actual short-term incentive payouts (Exhibit B-7, Attachment 226.1.1, p. 8). Of concern to the Commission Panel is the extent to which actual Total Cash paid to executives for base salary and STI exceeds the target or median Total Cash paid as indicated in the confidential report (Exhibit B-1-1, Appendix C 2). As noted previously in Section 3.1.2.2, FBC has stated that its approach to total compensation is to be in the median level in its peer group. The Panel accepts this. However, if there is a shortfall in the amount of executive compensation as pointed out by the Hay Group, it is with the long-term elements of the plan, not the STI. In the Panel's judgment it is not reasonable to offset any shortfall in long-term incentives of the executive compensation plan by increasing the STI to a level that is well above target. **Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder.**

In summary, FBC is to calculate the STIP payment based on the target median and then deduct 30 percent of this calculation to arrive at the amount to be borne by the ratepayer. Any STIP amounts paid in addition to this are to be borne by the shareholder.

As part of its Compliance Filing, FBC is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount that would have been spent if only the target STI had been met (as per page 9 of the Executive Compensation Benchmarking, Exhibit

B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M. If required, the filing may be made on a confidential basis with reasons.

3.1.3 Base Capital

There is considerable disagreement among the parties with respect to the inclusion of capital expenditures for FBC within the PBR. Much of this disagreement stems from concern that the methodology chosen by FBC leaves too much open to the Company's judgement and because of this, the customer is disadvantaged. The Commission Panel holds similar concerns. This was discussed in Section 2.3.5 where the Panel considered these matters and has determined that a further review of the capital exemption is required. This is to be addressed further in accordance with the timetable set out by the Panel in Section 2.3.5 with the expectation that the parties will recommend an appropriate threshold for capital to be included in the PBR formula. Until that time, the Panel has approved FBC's proposed approach to formula capital. Accordingly, this section will only deal with setting a base capital for the period up to and including 2015.

Similar to the approach taken with O&M, FBC has used the 2013 approved capital expenditures of $101.970 million from the 2012–2013 Decision as its starting point for the capital formula. Then, the following adjustments are made:

- Major projects such as Polychlorinated Biphenyls (PCB) environmental compliance, the Kelowna Bulk Transformer Capacity Addition, the Trail Office Lease/Purchase, the Kootenay Long Term Facility and Advanced Metering Infrastructure totalling $54.882 million are deducted.
- Adjustments for 2013 non-controllable items to account for the return of PST and pension and OPEB amounts related to higher actuarial estimates are then made. FBC expects the pension amounts to decrease over the 2014 to 2018 period.

(Exhibit B-1, pp. 56–59, pp. 180–182; FBC Final Argument pp. 24–28)

These adjustments are outlined in detail, by capital category, in Table 3.7 below and result in a 2013 Base of $49.180 million. This is comprised of $19.194 million for Sustainment Capital, $19.760 million for Growth Capital (primarily for new connects), $8.134 million for Other Capital and $1.723 million for PST and pension adjustments.

Table 3.7 2013 Base Adjustments ($ thousands)

	2013 Approved	Less Major Projects	Applicable to Formula	PST	Pension	2013 Base
Generation Sustainment Capital						
All Plants Concrete and Structural Rehabilitation	408	-	408			
Lower Bonnington Powerhouse Windows	4	-	4			
All Plants Minor Sustainment Projects	1,032	-	1,032			
Upper Bonnington, South Slocan & Corra Linn Powerhouse Windows	131	-	131			
Upper Bonnington Old Plant Various Unit Upgrades	378	-	378			
Lower & Upper Bonnington & Corra Linn Fire Panels	231	-	231			
All Plants Public Safety and Security	179	-	179			
	2,363	**-**	**2,363**	**19**	**86**	**2,468**
Transmission, Stations and Distribution Sustainment Capital						
Transmission Sustainment	5,378	-	5,378			
Station Sustainment	1,723	-	1,723			
PCB Environmental Compliance	9,021	(9,021)	-			
Distribution Sustainment	8,828	-	8,828			
Communications Upgrades	318	-	318			
SCADA System Upgrades	584	-	584			
	25,852	**(9,021)**	**16,831**	**132**	**616**	**17,579**
SUSTAINMENT CAPITAL	**28,215**	**(9,021)**	**19,194**	**151**	**702**	**20,047**
Transmission, Stations and Distribution Growth Capital						
Ellison to Sexsmith Transmission Tie	318	-	318			
Kelowna Bulk Transformer Capacity Addition	2,865	(2,865)	-			
New Connects	17,198	-	17,198			
Ellison Feeder 2 to Sexsmith Feeder 1 Tie	908	-	908			
Distribution Small Growth Projects	714	-	714			
Distribution Unplanned Growth Projects	622	-	622			
GROWTH CAPITAL	**22,625**	**(2,865)**	**19,760**	**155**	**723**	**20,638**
OTHER CAPITAL						
Buildings	769	-	769			
Furniture & Fixtures	106	-	106			
Fleet	2,260	-	2,260			
Telecommunications	159	-	159			
Meters	353	-	353			
Tools	398	-	398			
Information Systems	4,089	-	4,089			
Trail Office Lease Purchase	10,000	(10,000)	-			
Kootenay Long Term Facility	7,980	(7,980)	-			
Okanagan Long Term Solution	31	(31)	-			
Advanced Metering Infrastructure	24,985	(24,985)	-			
	51,130	**(42,996)**	**8,134**	**64**	**298**	**8,495**
TOTAL CAPITAL EXPENDITURES	**101,970**	**(54,882)**	**47,088**	**369**	**1,723**	**49,180**

(Source: Exhibit B-1, p. 181)

FBC describes its capital categories as follows:

- "Sustainment Capital – Consists of expenditures for system reinforcements, replacements and upgrades to generation, transmission and distribution assets to ensure safety, integrity and reliability.
- Growth Capital – Consists of expenditures for infrastructure upgrades required to meet customer and associated load growth.

- Other Capital – Consists of expenditures for Information Systems, Vehicles, Metering, Telecommunications, Facilities, and Tools and Equipment."

(Exhibit B-1, p. 178)

FBC provides an illustration of how the formula will work in Table 3.8 below.

Table 3.8 PBR Capital Formula Inputs and 5-Year Forecasts

Line No.	Particulars	2013 Base	2014 Formula	2015 Formula	2016 Formula	2017 Formula	2018 Formula
		(1)	(2)	(3)	(4)	(5)	(6)
1	2013 Base Capital ($000)	$ 49,180					
2	Less Capital Tracked Outside of Formula						
3	Pension/OPEB (Capital portion)	(6,741)					
4		42,439					
5							
6	Average Number of Customers	128,796	129,770	130,922	132,142	133,365	134,687
7	% Change in Customers		0.76%	0.89%	0.93%	0.94%	0.98%
8							
9	Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
10							
11	Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
12							
13	I-X Mechanism (1+I-X)		101.81%	101.92%	101.84%	101.86%	101.80%
14							
15	Net Inflation Factor ((1 + Line 7) * Line 13)		102.58%	102.82%	102.79%	102.82%	102.79%
16							
15	Formulaic Capital (Line 15 * Prior Year)		43,534	44,764	46,012	47,309	48,630
16	Add: Capital Tracked Outside of Formula						
17	Pension/OPEB (Capital portion)	6,741	6,396	5,952	5,508	5,133	4,826
18	PCB Compliance - Substations		6,062				
19	Advanced Metering Infrastructure Project		16,765	18,233	583	741	604
20							
21	Total Capital Under PBR		72,758	68,950	52,103	53,183	54,060

(Source: Exhibit B-1, p. 58)

Table 3.7 shows how the base capital will be adjusted annually. This takes into account the percentage change in the average number of customers and the application of the I-X formula to arrive at its current estimate of the formulaic capital for each of the PBR years. Added to this is capital for PCB Compliance (substations), AMI and the capital portion of Pension/OPEB. These amounts vary each year and are proposed to be covered under PBR but are tracked outside of the formula. As a result, the amount of capital proposed to be covered under PBR varies from $72.758 million in 2014 to amounts in the $52 to $54 million range in years 2016 to 2018.

In Table C5-3 of the Application (Exhibit B-1, p. 182), FBC provides its forecast of capital expenditures over the PBR period. These indicate that the Company's expectations are that given a non PBR environment, Forecast Sustainment Capital will exceed, Growth Capital will be lower and

Other Capital will be higher than those amounts generated by the formula and driven by 2013 Approved amounts. In total, the amounts generated by the formula are 3.1 percent lower than FBC's five-year capital forecast.

Intervener Submissions

CEC notes that FBC's forecast capital expenditures vary significantly by major functional area and by total capital classification. It points out that 2014 capital expenditures are forecast to be 50 percent higher when compared to the Approved 2013 Base Sustainment Capital. This drops by $6.3 million in 2015. In addition, other functional areas have no capital forecast in some years.

CEC also raises concern as to FBC's history of under spending its capital against approved amounts and whether the Company is able to accurately predict future costs. To support its argument, it relies upon FBC's response to BCUC IR 1.148.3 showing that since 2008, capital expenditures have been below approved capital by amounts ranging from three to 37 percent. CEC acknowledges that extenuating circumstances contributed to under-expenditures in 2012 and 2013 and its comments refer to total capital spending but submits that this nonetheless provides an indication of the magnitude of the variance. The historical results suggest that actual capital expenditures can be lower than approved by amounts that are far greater than the 3.1 percent as forecast by FBC. CEC points out that there is a real possibility that FBC could significantly underspend against PBR approved amounts with little short-term impact on safety, performance or reliability. Stakeholders may perceive this potential for significant losses or gains as contrary to the "just and reasonable" rate principle. (CEC FBC Non PBR Final Argument, Base Capital, pp. 5–6)

ICG agrees with the classification of capital projects as base or major capital but argues that the evidence does not provide criteria that could consistently identify those projects that would fall outside of base capital. A reliance on a formula approach to determine capital expenditure targets is not likely to produce better results than the project-by-project analysis conducted in the earlier PBR. ICG urges the Commission to reject the FBC PBR Plan proposal "at least until FBC refines the method for ensuring only recurrent expenditures are in base capital, and until FBC can measure efficiency gains (savings) resulting from efficiency initiatives." However, if the Commission does include capital expenditures in the PBR Plan, ICG recommends that the base capital be set on 2013 Actual capital expenditures rather than the 2013 Approved amounts. (ICG Final Argument, pp. 17–21)

FBC Reply

FBC disputes the CEC argument concerning consistently under spending its approved capital. It points out that even CEC agrees that there were extenuating circumstances in 2012 and 2013 that led to the lower spending levels. In addition, the Company asserts that the largest part of the variance between actual and approved amounts were those related to CPCNs. Because the Company is seeking to have CPCNs tracked outside of the formula, this problem should be alleviated.

FBC argues that CEC has ignored the fact that the PBR formula is designed to be applied at the aggregate level rather than the functional level which is in keeping with the PBR guiding principle of 'keeping it simple.' FBC states "the type of granular analysis conducted by CEC is contrary to this principle and unnecessarily increases the complexity of the mechanism." Its position is that determining the capital at the aggregate level allows it to determine the appropriate allocation of overall funds. (FBC PBR Reply, pp. 35–36)

Concerning ICG's submissions, FBC states that it is not appropriate to use a test of "non-recurring" to identify capital falling outside of the formula arguing that it is appropriate to include expenditures that are generally knowable and manageable based on past budgeting experience and customer growth. CPCN projects should not be placed under the formula as they represent large, discreet and "lumpy" investments. (FBC PBR Reply, p. 41)

Commission Determination

The positions of the Interveners with respect to the determination of base capital seem to be founded on past experience with actual capital expenditures as compared to approved capital expenditures. CEC has taken a historical view and has compared total actual versus approved capital as evidence supporting its position that history is likely to repeat itself in the current PBR. ICG, while refraining from referring to specific numbers, has urged the Commission to consider the current capital expenditures in light of past capital expenditures.

The Commission Panel finds the CEC and ICG arguments to be unpersuasive and puts little weight on them. Both CEC and ICG have made their submissions based on variances in total capital expenditures with no recognition of the steps taken by Fortis to adjust the capital covered under the PBR formula down in recognition of those projects which are non-recurring or of a one-off nature. Nor have their arguments considered the implications of these adjustments. As a result, the Panel considers this to be an "apples and oranges" proposition with little basis for comparison. However, as noted in Section 2.3.5, the Panel has determined that a further review of the capital is required. This could result in a larger dollar threshold for capital included in the PBR formula. In considering changes to the scope of capital projects and setting a dollar threshold, the Panel acknowledges it must consider FBC's past history and be satisfied that the new capital base will reflect what is realistically required.

FBC has proposed the following with respect to setting the base capital for the PBR:

1. Acceptance of the 2013 Approved Capital Expenditures of $101.970 million as the starting point for determining the base.
2. A deduction of $54.882 million from this amount in recognition of various non-recurring projects.
3. The addition of adjustments for non-controllable items (Pension/OPEB, PCB Compliance and the AMI project).

FBC has also included acceptance of the CPCN criteria as a means of excluding projects from the formula. This has been dealt with earlier and will not be further discussed.

The Commission Panel will review each of these in turn.

Acceptance of 2013 Approved Capital Expenditures as the Starting Point

The Commission Panel accepts the 2013 Approved Capital Expenditures as an appropriate starting point for determining the base capital. The Panel acknowledges that 2013 actual expenditures were less than approved but accepts that this was largely due to matters related to the labour disruption. As was discussed in Section 3.1.2, this amount has been scrutinized carefully in a recent regulatory proceeding and given the labour disruption in 2013, the Panel considers this to be the most reliable starting point.

Deductions of $54.882 million for Major projects

The Commission Panel accepts a deduction of $54.882 million from 2013 Approved Capital Expenditures as proposed by FBC. As argued by FBC, this amount is for non-recurring projects and CPCNs which are responsible for a significant part of the continuing variance between actual and approved capital spending levels. The Panel considers the tracking of these outside the formula as a reasonable approach at this time given the concerns raised by interveners with respect to total actual versus total approved capital expenditures. As outlined in Section 2.3.5, the matter of exclusions from the capital formula will be readdressed in 2015.

Addition of Adjustments for Non-Controllable Items

The Commission Panel accepts that there is a need to accommodate amounts for Pension/OPEB, PCB Compliance (substations) and the AMI project and these are to be tracked outside of the formula. However, for clarity purposes, the Panel affirms, as previously determined in Section 2.3.1 that the earning sharing mechanism will not apply to these amounts. The Earnings Sharing Mechanism (ESM) will apply to formulaic capital only.

In consideration of all of these factors, **the Commission Panel approves FBC's 2013 Base Capital as applied for, subject to further adjustment as directed elsewhere in this Decision**.

3.2 Accounting Policies

FBC seeks the following approvals for changes in its accounting policies, effective January 1, 2014:

a. Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports;

b. Approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense;

c. Approval to allocate Executive costs between FEI and FBC effective January 1, 2014, by way of applying the Massachusetts Formula;

d. Continued approval of FBC's direct overhead charging methodology; and

e. Continued approval of FBC's capitalized overhead rate of 20 percent.

Each of these topics will be addressed in the following sections.

3.2.1 <u>Discontinue Reconciliation of US GAAP to Canadian GAAP</u>

In Order G-117-11, the Commission approved FBC's request to adopt US Generally Accepted Accounting Principles (GAAP) for the period 2012–2014. As part of that Order, the Commission requested that FBC provide an annual reconciliation from US GAAP back to Canadian GAAP.

The 2012 reconciliation provided by FBC in the 2012 Annual Report (amounts reported under 2011 Canadian GAAP for financial reporting purposes to amounts reported under US GAAP for regulatory accounting) was filed as Exhibit A2-2 by staff in this proceeding.

FBC states that it no longer maintains specific accounting records in compliance with pre-2012 Canadian GAAP since it is not used for any other reporting purpose. Therefore, it is becoming increasingly complicated and costly to prepare this reconciliation on a prospective basis. (Exhibit B-1, p. 245)

FBC estimates that approximately one week was spent reviewing the reconciliation for 2012 and that continuing to prepare this reconciliation is expected to not only increase the future preparation and review time of its BCUC Annual Reports but that it also increases FBC's external actuarial costs. FBC also agrees that it will continue to be willing to communicate to the Commission any future accounting policy changes that will have an impact on setting customer rates. (Exhibit B-7, BCUC 1.174.3–1.174.4)

Based on these reasons, FBC requests approval to discontinue providing this reconciliation in its future Annual Reports. (FBC Non PBR Final Argument, pp. 47–48)

BCPSO supports FBC's request to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports. BCPSO's view is that the reconciliation becomes less informative each year, and the cost of performing the reconciliation is likely to grow, thus shifting the cost/benefit of this reconciliation over time. (BCPSO Non PBR Final Argument, p. 15)

No other Interveners commented on this issue.

Commission Determination

The Panel agrees with FBC that the reconciliation of US GAAP to pre-existing Canadian GAAP is no longer relevant and is therefore of limited use. The Panel also recognizes that continuing with this reconciliation creates unnecessary additional regulatory burden for FBC. **Accordingly, the Commission Panel approves discontinuance of the US GAAP to Canadian GAAP reconciliation. The Commission Panel directs FBC to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.**

3.2.2 Net-of-Tax Treatment of Pension/OPEB Funding

FBC seeks Commission approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective in 2014. Instead it proposes to add back the pension/OPEB expenses and deduct the contributions when performing income tax calculations (Exhibit B-1, p. 242). FBC states that the prepaid pension and OPEB liability deferral accounts are not amortized into rates in a manner similar to other deferral accounts that are subject to the net-of-tax treatment. Rather than being amortized, the prepaid pension and OPEB liability deferral accounts balances change based on the amount of employee benefit expenses recognized and contributions paid in each year. As such, these employee future benefit deferral accounts are not drawn down in the same manner as other deferral accounts and their related net-of-tax deferral balances. (Exhibit B-1, p. 242)

FBC states that this change is consistent with FEI's treatment, which was approved in Order G-141-09. Further, FBC submits that the net-of-tax treatment is not common practice in the rate-regulated utility industry and identified several utilities that do not use the net-of-tax treatment (Exhibit B-7, BCUC 1.215.3).

Intervener Submissions

BCPSO submits that the going-in rate must be adjusted to reflect the change from recording the deferral account on a net-of-tax basis to including the income tax impact in income tax expense. If this is done, ratepayers should be indifferent to the change. (BCPSO FBC Non PBR Final Argument, p. 15)

No other Interveners commented on this issue.

Commission Determination

The Commission Panel approves FBC's request to discontinue the net-of-tax treatment for the pension and OPEB funding differences as applied for. The prepaid pension and OPEB liability deferral account balances change each year based on the amount of employee benefit expenses recognized and contributions paid. Therefore, the Panel considers FBC's request for a different treatment to be reasonable. The reasoning is particularly appropriate since these deferral accounts are not drawn down in the same manner as other deferral accounts.

The Panel directs the existing net-of-tax balances of the pension and OPEB to be carried forward as a starting point for 2014, with future additions to both accounts to be on a pre-tax basis and the timing of tax deductions to be recognized in the calculation of income tax expense.

3.2.3 Allocate Executive costs by way of the Massachusetts Formula

As an alternative to relying upon management estimates of time for cost allocations, FBC proposes to allocate executive costs between FEI and FBC effective January 1, 2014, by applying the Massachusetts Formula. The Massachusetts Formula is extensively used in industry and is a composition allocator that determines the amount of time and effort for each executive. (FBC Non PBR Final Argument, p. 49) FBC states that the objective of seeking to use the Massachusetts Formula is not to increase or decrease executive labour O&M cost, but rather to adopt a simplified method of allocation (Exhibit B-24, BCUC 2.25.5).

Intervener Submissions

ICG supports the use of the Massachusetts Formula for the allocation of shared service costs between FEI and FBC (ICG Final Argument, p. 22).

No other Intervener made submissions.

Commission Determination

The Panel recognizes the simplified method of allocating executive time between FEI and FBC and recognizes the high level of integration between the two companies at the executive level. **FBC's proposed methodology utilizing the Massachusetts Formula is approved**.

The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.

3.2.4 Direct Overhead Loading

FBC utilizes direct overhead loading to allocate supervisory and administrative costs attributable to transmission and distribution (T&D) capital projects (Exhibit B-1, pp. 255–257; FBC Non PBR Final Argument, pp. 58–60). FBC explains that these costs are directly attributable to T&D capital projects and should be directly charged to these projects. However, for administrative efficiency these costs are charged directly into a holding account and then allocated to T&D capital using a Direct Overhead loading factor in a manner similar to how Capitalized Overhead is applied. (Exhibit B-7, BCUC 1.179.1)

FBC submits that it first introduced this methodology in its 2004 RRA for purposes of reducing the administrative burden associated with charging labour time and costs to individual projects. FBC has been charging these costs to capital consistently for the past 13 years. (Exhibit B-7, BCUC 1.179.3)

In compliance with the last RRA Decision, FBC obtained an external audit opinion on the appropriateness of the direct overhead loading methodology. In its report, KPMG "finds that FBC direct overhead loading methodology…to be a reasonable basis…and may continue to be appropriate" (Exhibit B-1-1, Appendix F3, KPMG Report, p. 5).

KPMG also confirmed "these costs are removed from the O&M pool" and do not result in duplicating the allocation of the capitalized overhead, "as the evaluation of direct overhead rate is conducted with these direct overhead loading costs excluded from the remaining corporate cost pool…" (Exhibit B-1-1, Appendix F3, KPMG Report, p. 29).

Intervener Submissions

ICG recommends the Commission Panel accept the methodology pro-tempore and direct FBC to review it again prior to the end of the PBR Period. ICG suggests that three departments — Environment, Finance and Procurement — appear to estimate the percentage of their activities related to T&D operations and then a percentage of their residual costs are capitalized based on the volume of work. Mr. Pullman recommends that a more rigorous analysis should be performed on FBC's time records rather than reliance on management's estimates. (ICG Final Argument, pp. 28–29)

FBC Reply

FBC submits that Mr. Pullman has not properly distinguished the issue of capitalized overhead and direct overhead and stresses the fact that the KPMG Review made specific reference to the Company's methodology not resulting in duplication. FBC's position is that further review of the methodology is not necessary. (FBC Non PBR Reply, pp. 34, 36–38)

Commission Determination

The proposed methodology of utilizing a T&D loading factor is a simplified method of allocating supervisory and administrative costs that are attributable to these types of capital projects. There is no evidence that this simplification results in duplication of allocations or any other issues of concern. Accordingly, **the Panel approves FBC to continue its Transmission and Distribution direct overhead loading allocation during the PBR period**.

The Panel agrees that FBC has complied with the previous directives by its filing of the KPMG Report and does not consider further evaluation to be required at this time.

3.2.5 Capitalized Overhead

FBC seeks approval to continue to use a capitalized overhead rate of 20 percent during the PBR period. FBC submits that it operates in a capital-intensive industry and while many activities can be charged directly to a specific project, others are not as directly attributable and therefore require the capitalized overhead allocation. (FBC Non PBR Final Argument, p. 51)

FBC obtained an audit review from KPMG and submits that its 20 percent rate is appropriate, there is no one universally accepted guideline for capitalizing overhead, and FBC's allocation method was found to be a reasonable (Exhibit B-1, pp. 251, 254; Exhibit B-1-1, Appendix F3, KPMG Report).

FBC submits that it is expecting regular capital expenditures over the PBR Period to remain at levels generally consistent with, or higher than, regular capital expenditures made during 2010 through

2013. Further, it notes that reducing the capitalized overhead rate will have rate impacts for FBC's customers.

The KPMG Report compares two different models to estimate FBC's capitalization rate: the Survey model, which proposes an overhead capitalization rate of approximately 15 percent; and the Mathematical model, which proposes a rate of 17 percent. KMPG found that the Survey model provides more transparent linkage of the unallocated overhead costs related to capital activities and therefore "believes that the more appropriate capitalization rate is approximately 15 percent." (FBC Exhibit B-1-1, Appendix F3, KPMG Report, p. 27)

FBC submits that the KPMG rate is "indicative in nature, but not definitive" and does not agree that its rate of 20 percent should be reduced (FBC Exhibit B-7, BCUC 1.178). However, FBC states that if the Panel were to direct it to reduce the rate then it would "recommend a phased in approach to the rate reduction in order to mitigate the impact on customer rates." (FBC Exhibit B-7, BCUC 1.178.4) As an alternative, FBC agrees that "[i]t could be possible to utilize a percentage of forecast capital expenditures as an overheads capitalized allocator, however that approach would introduce higher variability in customer rates." (FBC Exhibit B-7, BCUC 1.178.7)

Intervener Submissions

BCPSO submits that 20 percent is too high and refers to KPMG's study indicating an appropriate rate of 15 percent. BCPSO does not agree with FBC's characterization that a lower rate would have a negative rate impact because that would be a one-time hit, with positive rate impacts being experienced in each subsequent year. (BCPSO FBC Non PBR Final Argument, p. 16)

ICG also highlights the inconsistency between FBC's current overhead capitalization rate of 20 percent versus the KPMG report and requests the Panel direct FBC to implement immediate changes to its capitalization policies. Mr. Pullman recommends the Commission direct FBC to determine its capitalized overhead as a function of its capital expenditures rather than its O&M expenses. Mr. Pullman further recommends that FBC be directed to capitalize overhead at 8 percent of capital expenditures instead of 20 percent of O&M. (ICG Final Argument, pp. 29–31)

FBC Reply

In response to ICG's recommendation for employing a capitalized overhead rate as a percentage of capital expenditures, FBC estimates the resulting rate impact may fluctuate between -1.2 percent to 6.3 percent during the PBR period. This will occur due to capital expenditure levels. Further FBC points out that ICG has provided no evidence as to why this percentage is appropriate. (FBC Non PBR Reply, pp. 32–33)

Commission Determination

The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014. This is the rate recommended by KPMG based on the audit report ordered by the Commission in FBC's last RRA Decision. The Panel considers the utilization of a rate recommended by FBC's external auditors is reasonable and prudent and thus an appropriate rate for the PBR period. The Panel accepts that reducing the capitalized overhead rate to 15 percent will have a rate impact of approximately 1.25 percent for FBC (Exhibit B-7, BCUC 1.178.1). However, over time this will be mitigated by a lower amount being capitalized, resulting in lower rate impacts on an ongoing basis.

Pertaining to Mr. Pullman's recommendation for determining capitalized overhead as a function of its capital expenditures, the Panel finds that ICG provided no evidence to suggest this method has been employed in other jurisdictions. Furthermore, the Panel finds that the suggested methodology would lead to lumpy results with no significant evidence of offsetting benefits (Exhibit C-10-7, ICG 1.2.2). Thus, the Panel is not persuaded there at this time to consider moving away from current practice.

3.2.6 Capitalization of Annual Software Costs

The capitalization of annual software costs was not requested by FBC in this Application. However, this request was proposed by FEI in its 2014–2018 PBR RRA. FEI is requesting approval to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. FEI states that the costs allocated to capital using this methodology are to fund only the upgrade component of the annual costs which extend the life of the affected software assets. (FEI Exhibit B-1, p. 265) The impact of this capitalization methodology is a re-allocation of approximately 43 percent of FEI's annual vendor software costs from O&M to Capital. FEI states in its evidence that this requested change is consistent with the treatment employed by FBC.

Commission Determination

Given the description of annual software costs proposed by FEI, the Panel considers these to be annual licencing fees associated with software. **The Commission Panel agrees and also considers it inappropriate for FBC to capitalize these recurring fees and directs FBC to expense its annual software costs in a manner consistent with the direction provided to FEI by the Commission in Section 3.2.3 of the FEI 2014–2018 PBR RRA Decision.**

As part of its Compliance Filing, FBC is directed provide the following information: (i) the total amount paid in 2013 for annual software costs; (ii) the amounts originally included in FBC's Application for 2013 Base O&M and 2013 Base Capital related to annual software costs; and (iii) the increase to FBC's 2013 Base O&M as a result of this change in treatment of annual software costs and the resulting decrease to FBC's 2013 Base Capital.

Consistency between FBC and FEI can be beneficial and in the Panel's best judgement, it is appropriate for both FBC and FEI to treat annual software upgrade costs in the same manner. The Panel notes that expensing annual software costs is acceptable practice under US GAAP.

3.3 Deferral Accounts

FBC is requesting a number of new rate base deferral accounts and changes to existing deferral accounts. Additionally, there are a number of issues that arose during the last RRA that FBC proposes that this Panel revisit. These issues are further discussed in the following sections.

3.3.1 Deferral Account Financing

FBC requests revisiting the Commission's Decision in the 2012–2013 RRA, which it submits was incorrect (FBC Reply, p. 38). FBC proposes that deferral accounts should earn the weighted average cost of capital (WACC), which includes both equity and debt return (Exhibit B-1, p. 246; FBC Reply, p. 38).

In the 2012–2013 RRA Decision, the Commission found that "current period charges are not 'investments' which attract a capital return, they are deferred operating costs/current period expenses which, … in the Panel's view should not attract rate base rate of return." The Commission also stated that: "For expenditures which are amortized beyond one year, the Panel finds that the appropriate return is FortisBC's WACD. The Panel further finds that for true-up deferral accounts which are, by their very nature, a short term deferral, the appropriate interest return is FortisBC's short term interest cost." (p. 105)

FBC's concerns with the current method are:

- Inconsistency between FBC's deferral accounts, as some are financed at the WACC, some are at the weighted average cost of debt (WACD) or short term interest, even though they have similar characteristics.
- Inconsistency with past practice. The last RRA decision was the first time the Commission introduced this distinction between capital and operating expenses in deferral accounts.
- The distinction between capital and operating expenses is inappropriately applied because once an item is given deferral treatment it ceases to be an operating expense.
- WACC reflects the company's cost of financing because it attempts to mirror the approved capital structure.
- Inconsistency with other Fortis companies.
- Inconsistency with other jurisdictions, like Alberta.

(FBC Non PBR Final Argument, pp. 64–74; FBC Reply, p. 39)

FBC also believes that the Commission erred in making a distinction between “investments” and “deferred operating costs/current period expenses” in the last RRA decision (FBC Non PBR Final Argument, p. 65).

Intervener Submissions

BCPSO argues that FBC did not look at other jurisdictions outside of Alberta. For example, Ontario applies the prescribed interest rate for Board-approved deferral and variance accounts to be equal to the Bankers' Acceptances three-month rate, as published on the Bank of Canada's website, plus a spread of 25 basis points. BCPSO submits that the approval sought by FBC should not be granted, and that the approach determined in the 2012–2013 RRA Decision should be maintained. (BCPSO FBC Non PBR Final Argument, s. 3.2)

ICG submits that FBC’s deferral accounts should be financed in a manner similar to BC Hydro.

FBC Reply

FBC’s Reply points out that the Ontario method is not in evidence and BCPSO did not raise this evidence until now (FBC Non PBR Reply, p. 43).

In response to ICG’s submission, FBC drew several distinctions between an investor-owned utility versus a crown corporation (FBC Non PBR Reply, pp. 41–42).

Commission Determination

The Commission Panel recognizes different treatment exists between FEI and FBC in the handling of carrying costs for deferral accounts; however, the Panel is not persuaded by the evidence within this proceeding that FBC's deferral account financing, as it is currently approved in the 2012-2013 FBC RRA Decision, should be revisited. The Commission Panel therefore rejects the FBC proposal to revisit the 2012–2013 FBC RRA Decision.

In light of the concerns raised by FBC, the Panel believes that there is merit in looking at this issue more broadly. As such, the Panel requests the Commission initiate a review of deferral accounts and related carrying costs in the near future.

3.3.2 New Deferral Account Requests

FBC is seeking the establishment of several new deferral accounts. These are summarized in the table below:

Table 3.9 New Deferral Accounts Requested

NEW ACCOUNTS – RATE BASE	
Account Name	**FBC Request**
Rate Stabilization Deferral Mechanism (RSDM)	5-year amortization starting January 1, 2014
Earnings Sharing Mechanism (ESM) Deferral	Balance at December 31 of each year to be amortized into rates in the subsequent year
BC Hydro Application for a Power Purchase Agreement with FBC (RS 3808)	1-year amortization period commencing in 2014
Generic Cost of Capital Revenue Requirement Impact	1-year amortization period commencing in 2014
2014–2018 Annual Reviews	Amortize the following year
Insurance Expense Variance	Amortize the following year
Interest Expense Variance	3–year amortization
Tax Variance	Amortize following year
Property Tax Variance	3–year amortization
NEW ACCOUNTS — NON-RATE BASE	
Account Name	**FBC Request**
CPCN Projects Preliminary Engineering	Preliminary and investigative costs for CPCNs, attracting AFUDC. Transfer to capital project upon CPCN approval

(Adapted from Exhibit B-1, pp. 261–264, 273; FBC Non PBR Final Argument, pp. 74–80)

The Panel will address each of these now.

3.3.2.1 RSDM Deferral Account

FBC submits that the Rate Stabilization Deferral Mechanism (RSDM) deferral account is a mechanism for mitigating rate variability over the PBR Period with a five-year amortization starting January 1, 2014.

FBC proposes that the revenue requirement forecast during the PBR term be levelized and states that this RSDM has been proposed, in part, due to Order E-15-12 which accepted the Waneta Capacity Purchase Agreement (WAX CAPA) (Exhibit B-1, pp. 3, 261). In Recital I of Order E-15-12, the Commission recognized that WAX CAPA has the potential for disproportionate rate impacts in the early years of the agreement and the Commission directed FBC to "develop a rate smoothing proposal for the Commission's approval either through a separate submission or with the next Revenue Requirements Application."

FBC states that in the absence of this account, ratepayers will face a rate decrease in 2014 followed by a larger rate increase in 2015:

Figure 1 Comparison of Rate Increase Scenarios

(Source: Exhibit B-1-6, Figure B7-1)

The rate increases attributed to the WAX CAPA in year 2015 and in year 2016 before implementation of the rate smoothing mechanism are as follows:

- Rate increases attributed to the WAX CAPA in year 2015: 7 percent (approximately)

- Rate increases attributed to the WAX CAPA in year 2016: 4 percent (approximately)

(Exhibit B-15, ICG 1.1.2)

FBC submits that there are two basic assumptions to the proposed RSDM:

1. The rate stabilization amount in 2014 and its subsequent amortization during 2015–2018 should be such as to generate a 3.3 percent Rate Impact in 2014 followed by a uniform Rate Impact thereafter during 2015–2018; and
2. The rate stabilization amount in 2014 and its subsequent amortizations during 2015–2018 should be such that it balances to zero by the end of 2018. (Exhibit B-1-6, Table D4-2, p. 261)

BCPSO is the only intervener that commented on FBC's proposed RSDM and indicates that it has no concerns. (BCPSO Non PBR Final Argument, p. 18)

Commission Determination

The Panel has considered Order E-15-12, accepting FBC's WAX CAPA as an energy supply contract, directing FBC to "develop a rate smoothing proposal." This directive is an instruction to FBC to develop a rate-smoothing proposal for the impact of WAX CAPA only. It did not contemplate a rate-smoothing proposal combining the accumulated impact of both WAX CAPA *plus* rate impacts as a result of the PBR plan. The Commission Panel does not agree that these should be combined.

FBC's proposed treatment for the RSDM is essentially a deferral account through which all of the PBR's Revenue Requirements will be collected and flowed through under the guise of providing smooth rates. This raises the concern that there will be a lack of transparency created by the resulting levelized rate impact which may in turn obscure stakeholders' abilities to assess whether the PBR plan has been a success, particularly when stakeholders see a flat rate year over year.

The Commission Panel denies FBC's proposal to establish the RSDM combining the impact of WAX CAPA and other PBR rate impacts.

In its Compliance Filing, FBC must recalculate and show the 2014 revenue requirement and rate impact without the rate smoothing effect of the RSDM. FBC must also propose to the

Commission a method to treat the revenue requirement impact between the interim rate increase approved under Order G-151-13 and the rate resulting from this Decision. As stated in Order E-15-12, the Commission is prepared to consider a rate-smoothing proposal to deal with the impact of WAX CAPA.

3.3.2.2 ESM Deferral Account

FBC proposes to record amounts above or below the approved ROE in the requested ESM deferral account for either refund to or recovery from customers in the subsequent year.

BCPSO was the only Intervener to comment on the proposed ESM deferral account, submitting that it has "no particular concerns with the BCUC approving the RSDM or ESM deferral accounts." (BCPSO Non PBR Final Argument, p. 18)

Commission Determination

The Commission Panel approves FBC's proposal to establish an ESM deferral account. The Commission Panel considers the use of this deferral account to be an appropriate mechanism for refunding or recovering from customers the 50 percent of amounts above or below the approved ROE.

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be at FBC's short-term interest rate.

3.3.2.3 New Power Purchase Agreement Application Deferral Account

On May 24, 2013, BC Hydro filed an application for approval of a new long term Power Purchase Agreement (PPA) with FBC. FBC states that as an active participant in this regulatory proceeding it would incur costs related to responding to IRs and may potentially incur other costs depending on the scope and type of process determined by the Commission. Accordingly, FBC has requested approval to record the costs related to this proceeding in a deferral account. (Exhibit B-1, p. 262)

FBC originally forecast a 2013 addition to this deferral account of $175,000 based on the assumption that the application would undergo an Oral Hearing process (Exhibit B-7, BCUC 1.186.1).

Pursuant to Order G-117-13, the Commission established a Written Hearing process for review of the BC Hydro PPA. When asked if the 2013 addition to the deferral account should be reduced based on this determination, FBC stated that it did not reforecast the addition to the deferral account in its Evidentiary Update because any variances from forecast deferral account balances would be trued up. (Exhibit B-24, BCUC 2.57.1)

No Interveners commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the BC Hydro Application for New Power Purchase Agreement with FBC deferral account as applied for by FBC. The Panel considers this treatment to be consistent with past deferral accounts approved for application-related costs. **However, the Commission Panel directs FBC to update its forecast addition to the deferral account as it relates to the Written Hearing as part of its Compliance Filing.**

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with FBC's 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate (p. 105).

3.3.2.4 Generic Cost of Capital Revenue Requirements Impact Deferral Account

FBC requests approval to establish the Generic Cost of Capital (GCOC) Revenue Requirements Impact deferral account to record the 2013 revenue requirements impact of the Stage 1 GCOC Decision. It proposes to amortize the deferred balance into rates in 2014. FBC also proposes to record and flow-through any further revenue requirements impacts resulting from the Stage 2

GCOC Decision as soon as reasonably possible following the decision, taking into account the effective date of the Stage 2 order. (Exhibit B-1, p. 262)

No Interveners commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the GCOC Revenue Requirements Impact deferral account. The Panel considers this treatment to be appropriate and consistent with past deferral account treatment given the proposed amortization.

The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate.

3.3.2.5 2014–2018 Annual Reviews Deferral Account

As part of the proposed PBR Plan, FBC plans to hold Annual Reviews for the purpose of setting rates for each upcoming year. The cost of the Annual Reviews is proposed to be recorded in the 2014–2018 Annual Reviews deferral account, the balance of which FBC proposes to amortize into rates in the subsequent year. (Exhibit B-1, p. 264)

No Interveners commented on this new deferral account request.

Commission Determination

The Commission Panel approves the establishment of the 2014–2018 Annual Reviews Deferral Account. The balance of this account is to be amortized in the year following each Annual Review at FBC's short-term interest rate.

3.3.2.6 Deferral Accounts Related to Flow-Through Items Under PBR

As described in Section 2.2.5.1 of this Decision, the Panel has denied the establishment of the following deferral accounts to record the variances between forecast and actual flow-through expenditures:

- Insurance Expense Variance;
- Interest Expense Variance;
- Tax Variance; and
- Property Tax Variance.

FBC also proposes the continuation of its Power Purchase Expense Variance deferral account and its Revenue Variance deferral account which were approved pursuant to Order G-110-12 (Exhibit B-1, p. 62). FBC states that any variances between actual and forecast sales revenue will accrue to the Revenue Variance deferral account with the majority of variances attributable to weather related to load variances, customer usage rates and customer count (Exhibit B-1, p. 269). Both the Power Purchase Expense Variance deferral account and the Revenue Variance deferral account have one-year amortization periods (Exhibit B-1-1, Appendix F4).

No Interveners commented on this matter.

Commission Determination

In keeping with the Panel's discussions and determinations for FBC's Flow-Through Items (Section 2.2.5.1 of this Decision), the Panel is not persuaded that continuation of the Power Purchase Expense Variance and Revenue Variance deferral accounts are necessary in order to allow for the flow through of these expenditures and revenues during the PBR. This is particularly relevant given the fact that these deferral accounts only have one-year amortization periods and thus are not being utilized for rate smoothing purposes. **Accordingly, the Panel directs FBC to discontinue the Power Purchase Expense deferral account and its related Revenue Variance deferral account during the PBR term. These expenses and revenues shall be flowed through to ratepayers each year through the annual flow-through mechanism.**

In its Compliance Filing, FBC is directed to provide its 2013 ending balances in these deferral accounts and illustrate the rate impact of flowing through these variances to 2014 rates. Variances between FBC's forecast and actual results in 2014 and beyond shall to be flowed through to ratepayers annually.

3.3.2.7 CPCN Projects Preliminary Engineering Non Rate Base Deferral Account

FBC submits that it incurs preliminary and investigative engineering costs in the development of capital projects subject to CPCN applications. It states that it does not intend to include in revenue requirements the impact of forecast CPCN projects until approved and added to its plant in service. FBC therefore, considers it is appropriate to retain the preliminary and investigative costs outside of rate base and attracting Allowance for Funds Used During Construction (AFUDC). (Exhibit B-1, p. 273) FBC requests approval to establish the non-rate base CPCN Projects Preliminary Engineering deferral account. It proposes to transfer the costs in the requested non-rate base deferral account to the applicable capital project once the capital project is approved and added to plant in service. (Exhibit B-1, Table A2-1, p. 8)

FBC stated that if a capital project does not proceed, the preliminary and investigative engineering costs are not eligible for capitalization. However, as long as the costs were prudently incurred, they are eligible for recovery through rates. Therefore, FBC would likely apply to the Commission for inclusion in the subsequent revenue requirements application. (Exhibit B-24, BCUC IR 2.68.1)

No Interveners commented on this issue.

Commission Determination

In the FBC 2012–2013 RRA Decision, the Commission determined that "Preliminary and Investigative Charges can be separated into two groups:

- Those costs which at a future time may become capital projects.

- Those that contribute to the development of Plans, which are a regulatory requirement but are not actual capital projects." (p. 112)

The Commission further stated: "Those projects which may in the future become capital projects are more properly considered operating expenses as they are not yet part of an approved capital project. Therefore, the Commission Panel directs that any approved deferral accounts for these costs attract a financing charge at FortisBC's WACD until such time as they become part of a specific capital project.**"** (pp. 112–113)

Consistent with the Commission's determinations in the FBC 2012–2013 RRA Decision, **the Commission Panel approves the establishment of the non-rate base CPCN Projects Preliminary Engineering deferral account**, as the costs to be included in this deferral account fall under the category of "costs which at a future time may become capital projects", as described in the FBC 2012–2013 RRA Decision. However, **the Commission Panel rejects FBC's proposal to apply AFUDC to this new deferral account** as it is not consistent with the determinations made in the previous RRA decision (p. 105). Accordingly, **the Panel directs FBC to comply with the previous Commission decision and apply carrying costs based on FBC's WACD to this deferral account starting in 2014.** The Panel also notes that the decision to proceed with a capital project should generally be made within three years. This is consistent with the Commission's directive that deferral accounts "with costs accruing beyond a three year period and where no CPCN has been applied-for or expenditure schedule filed, be amortized into rates" [bold in original] (p. 106).

3.3.3 Requested Changes to Existing Deferral Accounts

FBC has made a number of requests for new or modified amortization periods. These requests are summarized in the table below, then discussed in detail following:

Table 3.10 Amortization Period of Various Deferral Accounts

AMORTIZATION PERIOD – NEW OR MODIFIED – RATE BASE	
Account Name	**Request**
Demand-Side Management	Change from 10 year to 15 year amortization period
On-Bill Financing Pilot Program	Change from 10 year to 15 year amortization period
2014–2018 PBR Application	5 year amortization, commencing January 1, 2014
Pension and OPEB Expense Variance	Change from 3 year to 11 year amortization (EARSL), commencing January 1, 2014
City of Kelowna Acquisition Customer Benefit	1-year amortization commencing in 2014
City of Kelowna Acquisition Legal and Regulatory Costs	1-year amortization commencing in 2014
2014–2018 Capital Expenditure Plan (Preliminary Engineering cost)	2-year amortization beginning 2014
BCUC Generic Cost of Capital Proceeding	2-year amortization beginning in 2014
BCUC Inquiry into the MRS Program	1-year amortization commencing in 2014
Kettle Valley Expenditure Review	1-year amortization commencing in 2014
Transmission Customer Rate Design	1-year amortization commencing in 2014
2012 Mandatory Reliability Standards Audit	1-year amortization commencing in 2014
Mandatory Reliability Standards 2012–2013 Incremental O&M Expense	1-year amortization commencing in 2014

(Adapted from Exhibit B-1, pp. 246–269; FBC Non PBR Final Argument, pp. 81–83)

3.3.3.1 Demand-Side Management and On-Bill Financing Pilot Program Deferral Accounts

The Commission Panel addresses Demand-Side Management and On-Bill Financing Pilot Program deferral accounts in Section 4.2, Other DSM Requests.

3.3.3.2 2014–2018 PBR Application Deferral Account

The 2014–2018 PBR Application deferral account was approved pursuant to Order G-110-12 to record the costs related to the PBR Application. These costs include legal fees, costs for expert witnesses and consultants, costs related to independent validation of study results, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. FBC requests approval to amortize these deferred costs over five years commencing January 1, 2014. FBC states that this amortization period is appropriate because it represents the period covered by the PBR Application. (Exhibit B-1, p. 265)

Commission Determination

The Commission Panel approves the amortization of the 2014–2018 PBR Application deferral account over six years commencing January 1, 2014. The Panel considers aligning the amortization period for this deferral account with the PBR term to be appropriate because it is consistent with the treatment of past deferral accounts approved for revenue requirement application costs.

3.3.3.3 Pension and OPEB Expense Variance Deferral Account

FBC requests approval to extend the amortization period for the Pension and OPEB Expense Variance deferral account from the currently approved 3 years to 11 years, which is the Expected Average Remaining Service Life (EARSL) of benefit plans. (Exhibit B-1, p. 265)

FBC cites several reasons for the request:

1. It more appropriately allocates the costs over the future period to which they are applicable;
2. Large fluctuations in this account can occur from year to year and the longer amortization period will allow rate smoothing;
3. The use of EARSL to account for Pension/OPEB expense was previously accepted and approved by the Commission.

(Exhibit B-7, BCUC 1.214.2)

In response to BCUC IR 2.78.1, FBC submitted that the benefits of maintaining a shorter amortization period are lower debt and equity financing costs accumulating on the deferred balance and a resultant lower cost to ratepayers. FBC also submitted that maintaining the shorter amortization period would put upward pressure on revenue requirements through the increased amortization expense during the early part of the PBR period due to the fact that there is an estimated $9.4 million variance in 2012 and 2013 pension and OPEB expense to be recovered from customers over a shorter period of time. FBC noted that pension and OPEB costs over the 2014–2018 PBR period are unknown as is the impact on revenue requirements. (Exhibit B-24, BCUC 2.78.1)

Commission Determination

The Commission Panel denies FBC's request to change the Pension & OPEB Expense Variance deferral account amortization period from three years to the EARSL. FBC must therefore continue amortizing this deferral account over three years. The Panel recognizes that larger variances have been experienced in recent years. However, the Panel is not persuaded that deferring these costs so far into the future is appropriate or beneficial to ratepayers, particularly when taking into account the increased cost to ratepayers caused by the larger accrual of financing costs which would result if the deferral account balance was amortized over the longer time period.

3.3.3.4 City of Kelowna Related Deferral Accounts

The City of Kelowna Acquisition Customer Benefit deferral account was approved pursuant to Order C-4-13 to capture the 2013 Customer Benefit resulting from FBC's purchase of the utility assets of the City of Kelowna, including an adjustment to the Revenue Variance deferral account. FBC requests approval to amortize the $2.6 million deferred Customer Benefit into rates in 2014. The deferral account will then be discontinued effective January 1, 2015. (Exhibit B-1, p. 266; Exhibit B-1-1, Appendix F4)

FBC also requests approval to amortize the balance in the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014. The deferral account will also be discontinued effective January 1, 2015. (Exhibit B-1-6, p. 266; Exhibit B-1-1, Appendix F4)

Commission Determination

The Commission Panel approves the amortization of both the City of Kelowna Acquisition Customer Benefit deferral account and the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014. The Panel considers the short amortization period to be most appropriate given the nature and timing of when the costs/benefits were incurred. **The Panel directs that these deferral accounts be discontinued effective January 1, 2015, as proposed by FBC in the Application**.

3.3.3.5 2014–2018 Capital Expenditure Plan Deferral Account

Pursuant to Order G-110-12, approval was granted to FBC to capture the preliminary engineering costs for the preparation of its capital expenditure filing in the 2014–2018 Capital Expenditure Plan deferral account. FBC now requests approval to amortize this deferral account over two years starting in 2014. (Exhibit B-1, p. 266)

Commission Determination

The Commission Panel approves FBC's request to amortize the 2014–2018 Capital Expenditure Plan deferral account over two years.

3.3.3.6 2012 and 2013 Deferred Expenditures

On December 12, 2012, FBC applied to the Commission for approval to establish the following six new deferral accounts:

- BCUC Generic Cost of Capital (GCOC) Proceeding;
- BCUC Inquiry into the MRS Program;
- Kettle Valley Expenditure Review;
- Transmission Customer Rate Design;
- 2012 MRS Audit; and
- MRS 2012–2013 Incremental O&M Expense.

Following a review process, Commission Order G-23-13 directed FBC to transfer these costs into a single non-rate base holding deferral account with separate tracking and recording of costs. At that time, the Commission stated that it makes no determination on the cost recovery or amortization of these deferred costs and that FBC was to apply for recovery of these costs as part of its 2014 revenue requirements application. The Commission also stated that the issue of carrying costs for these incremental expenses, if approved, would be handled in the 2014 RRA.[15]

In the current Application, FBC is requesting approval for financing of the non-rate base account at the Company's WACC rate for 2013. It had previously sought WACD for all these deferral accounts in their 2012 deferral application. (Exhibit A2-3, p. 1) Further, FBC also seeks approval to transfer the balance in the non-rate base deferral account into the corresponding six rate base deferral accounts requested in the original December 12, 2012 application. (Exhibit B-1, p. 267)

BCPSO, in its Final Argument, states that FBC's proposed amortization periods are reasonable (BCPSO Non PBR Final Argument, p. 19).

No other intervener provided comments on these deferred costs.

Commission Determination

The Panel has reviewed the materials contained in Exhibit A2-3; FBC's application for these six deferral accounts, Commission staff IRs and FBC responses, and Commission Order G-23-13 with accompanying Reasons and makes the following determinations:

<u>BCUC Generic Cost of Capital Proceeding</u>

For the costs associated with the FBC GCOC proceeding, the Panel notes that FBC was notified of the GCOC after it had filed its 2012 RRA and its Evidentiary Update. Therefore, it would not be reasonable to expect FBC to have anticipated and forecast the costs associated with this

[15] Appendix A to Order G-23-13, pp. 2–3

proceeding. Accordingly, **the Commission Panel grants approval to FBC to establish a new deferral account to transfer the costs associated with the GCOC proceeding from the holding account to a separate deferral account for recovery from ratepayers. The Panel also approves the requested two-year amortization period, commencing in 2014.**

The Panel denies FBC's request to charge a WACC carrying charge to this deferral account. Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its WACD to this deferral account. FBC shall also apply its WACD to calculate the carrying charges on the 2013 balance**.

BCUC Inquiry into the MRS Program

With regards to the MRS Inquiry, this proceeding was initiated after FBC's 2012–2013 RRA Decision was issued and does not fall within the scope of FBC's anticipated MRS-related activities based on its 2012–2013 RRA. It is therefore reasonable to conclude that the related costs would be part of the utility's "ongoing effort to remain within auditable compliance with all standards" (FBC 2012–2013 RRA, Tab 4, p. 54). The Panel finds the request to defer costs associated with the BCUC MRS Inquiry to be reasonable. Accordingly, **FBC's requested deferral account for the BCUC Inquiry into the MRS Program and its requested amortization period of one year beginning in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account to calculate the carrying charges on the 2013 balance**.

Kettle Valley Expenditure Review

At the time of the 2012 deferral account application, FBC expected to incur approximately $75 thousand for the regulatory process (mostly legal fees). These costs are now $120 thousand higher than in the original application (Exhibit B-1-6, p. 267). The Commission Panel accepts that the Kettle Valley review was initiated by the Commission and is not a normal business expense which could be expected to be more accurately forecasted. Further, the Panel notes that Order G-36-12 approved all Kettle Valley expenditures with the exception of $65,734. **Given these circumstances, the Commission Panel finds that it is also reasonable to approve FBC's (legal) costs related to this inquiry. Accordingly, the Panel approves FBC's request to establish the Kettle Valley Expenditure Review deferral account with the amortization period of one year, starting in 2014. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC is directed to apply its short-term interest rate to calculate the carrying charges on the 2013 balance**.

Transmission and Self-Generating Customer Rate Design

FBC was notified of the Transmission Customer Rate Design review subsequent to its filing of the 2012–2013 RRA & ISP Application and its subsequent Evidentiary Update. Therefore, it would not have been reasonable for FBC to provide a forecast for this proceeding in its 2012–2013 RRA. In addition, the Panel considers the amount of costs forecast to be reasonable given the scope of work required by FBC. **Given these circumstances, FBC's deferral of the cost for the Transmission Customer Rate Design review and its requested amortization period of one year commencing in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.** Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC shall also apply its short-term interest rate to calculate the carrying charges on the 2013 balance**.

MRS Audit

In its 2012 deferral application, FBC states that it incurred $806,759 in costs for the MRS audit process in 2012 yet it had only budgeted $231,452 for internal labour costs. FBC therefore requested to defer the incremental labour costs of $575,306 for future recovery.

The Panel finds that the 2012 MRS audit was an inquiry that is unique and therefore accepts that it was difficult for FBC to accurately forecast the costs associated with this proceeding. **The Panel approves FBC's request for deferral of the incremental 2012 MRS costs with an amortization**

period of one year commencing in 2014. However, the Panel denies FBC's request to apply WACC to the deferral account. Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance**.

As the MRS audit is a non-recurring expenditure, it therefore should not be included in FBC's Base O&M. **In its Compliance Filing, FBC must confirm that these MRS audit expenses were not included in its proposed O&M base. To the extent that these MRS audit costs are included in the O&M base, they must be removed.**

MRS 2012–2013 Incremental O&M Expenses

In its 2012–2013 FBC RRA Decision, the Commission approved O&M expenses related to MRS totalling $1.2 million in 2012 and $1.2 million in 2013 (p. 78). In the December 2012 deferral account application, FBC requested an additional $0.3 million for 2012 and an additional $0.9 million for 2013 of MRS-related O&M expenses to be placed in a deferral account.

In explanation, Fortis states that "there was no provincial experience on which it could rely for calibration or verification of its estimates, nor was it able to obtain comparables from its counterparts in other jurisdictions." (Exhibit A2-3, BCUC 1.7.1.2) In the view of the Commission Panel, the MRS program is unique and accepts that there was little to rely upon in the preparation of accurate cost estimates. Therefore, in this instance we consider there to be justification for the cost overruns and are prepared to accept these additional costs.

The Panel approves the incremental costs ($0.3 million for 2012 and $0.9 million for 2013) related to its MRS O&M expense. The Panel grants approval for FBC to amortize these deferred costs into rates in 2014. The Panel denies FBC's request to apply WACC to the deferral account. Consistent with the directives in the FBC 2012–2013 RRA Decision, **the Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance**.

3.3.4 Other Rate Base Deferral Account Requests

3.3.4.1 On-Bill Financing Participant Loans Deferral Account

The Commission Panel makes specific determinations on the On-Bill Financing Participant Loans in Section 4.2.

3.3.4.2 Debt Issue Costs Deferral Account

FBC states that it calculates its debt issue costs, which include fees for auditors, legal, dealers, filings, rating agencies and trustees, using the straight-line method. These issuance costs are amortized over the term of the debt issuance. FBC indicates in its Application that it will be required to issue debentures in 2014 and that similar to its previously incurred debt issue costs, it intends to amortize the costs over the term of the debentures. A term of 30 years is currently forecast. (Exhibit B-1, p. 271)

Commission Determination

The Commission Panel approves the treatment of the deferred debt issue costs as applied for by FBC. The Panel considers this treatment to be appropriate as it is consistent with the past treatment of debt issue costs.

3.3.5 Request for Discontinuance of Deferral Accounts

Table 3.11 outlines the requests made by FBC related to the discontinuance of various deferral accounts:

Table 3.11 Summary of FBC's Request for Deferral Account Discontinuation

DEFERRAL ACCOUNT DISCONTINUATION REQUESTS	
Account Name	**Request and Reference**
Kelowna Bulk Transformer Capacity Addition Project	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 270)
Section 71 Filing (Waneta Expansion Power Purchase Agreement)	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, pp. 270–271)
Negotiation of new PPA between BC Hydro and FBC	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 271)
Right of Way Encroachment Litigation	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 271)
Trail Office Lease Cost	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 271)
Trail Office Rental to School District 20	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 271)
2011 Flow-Through and ROE Sharing Mechanism Adjustments	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2012 Deferred Revenue	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Harmonized Sales Tax Removal/Provincial Sales Tax Implementation	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Cost of Service and Rate Design Application	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2012–2013 Revenue Requirements Application and 2012 Integrated System Plan	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
2011 Revenue Requirement Application Costs	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
BC Hydro Waneta Transaction Proceeding	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Residential Inclining Block Rate Application	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Implementation of New Rate Structures	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Irrigation Rate Payer Group Consultation and Load Research	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Princeton Light and Power Deferred Pension Credit	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Princeton Light and Power Computer Software	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
US GAAP Conversion Costs	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Joint Pole use Audit, 2008	Discontinuation of the account effective January 1, 2014. (Exhibit B-1, p. 272)
Joint Pole use Audit, 2013	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)
Mandatory Reliability Standards Implementation	See Commission Determination regarding these incremental MRS costs in Section 3.3.3.6 of the Decision.
Revenue Protection	Amortization of account balance in 2014 and then discontinuance of the account effective January 1, 2015. (Exhibit B-1, p. 272)

(Adapted from Exhibit B-1, pp. 9–10)

No Interveners commented on FBC's request to discontinue these deferral accounts.

Commission Determination

The Commission Panel approves FBC's request to discontinue the deferral accounts listed in Table 3.11 above, and as outlined in the Application and in its Evidentiary Update.

4.0 DEMAND-SIDE MANAGEMENT

As part of this Revenue Requirement Application, under section 44.2 of the UCA, FBC is requesting approval to spend $3.0 million on Demand-Side Management (DSM) in 2014 (Exhibit B-1-1, Appendix H, p. 9). FBC withdrew its request for approval for the 2015–2018 DSM expenditures as a result of June 4, 2014 amendments to the DSM Regulations (Ministerial Order No 233). The amendments require that, from 2015, the avoided electricity cost for DSM be calculated using the long-run marginal cost (LRMC) of acquiring electricity generated from clean or renewable resources in BC. (T8:1386–1388)

FBC is also requesting approval to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years, to cease filing semi-annual reports on its DSM activities, and for changes to funding transfer rules. These requests are addressed below. (Exhibit B-1-1, Appendix H, pp. 18–19)

4.1 FBC's Expenditure Request for 2014

FBC is requesting approval to spend $3.0 million on DSM in 2014.
The 2014 proposed DSM expenditure schedule comprises DSM programs in the Residential, Commercial (or General Service) and Industrial sectors as well as funding for Supporting Initiatives and Planning and Evaluation (See Appendix C), and have a portfolio level BC cost effectiveness result of 1.4. (Exhibit B-1-1, Appendix H, p. 9)

FBC states that they have reduced DSM funding from $7.9 million approved for 2013 to $3.0 million for 2014 primarily as a result of a lower cost of energy forecast. FBC submits that its avoided cost of energy has decreased from $84.84/MWh in 2012 to $56.51/MWh. FBC bases this estimate on the cost of burning gas in a gas fired generator. (Exhibit B-1-1, Appendix H, p. 9, Attachment 4; FBC Non PBR Final Argument, pp. 108–109)

BCSEA submits that FBC's avoided cost for DSM is inaccurately low and is inappropriately based on FBC's short-run marginal cost, instead of being based on FBC's LRMC. BCSEA submits that there are also deficiencies in FBC's estimate of its short-run marginal cost, and that FBC's methodology does not reflect generation capacity costs or contribute to BC emission reduction and self-sufficiency objectives. (BCSEA FBC Non PBR Final Argument, pp. 12–15)

BCSEA also submits that, even assuming FBC's incorrect avoided cost estimate, the FBC DSM plan is not designed to produce all cost-effective efficiency and conservation savings (BCSEA Final Argument, p. 10). FBC disagrees with BCSEA's position, and counters that there is only a requirement to determine that expenditures are in the public interest, not that all cost-effective expenditures be made (FBC Non PBR Final Argument, p. 114).

BCPSO submits that the Commission should approve the reduced DSM spend as FBC's response to the reduction in LRMC is reasonable and FBC are still meeting the target of 50 percent of annual load growth (BCPSO FBC Non PBR Final Argument, p. 22). ICG submit that that the DSM spend should not be approved as the industrial sector DSM was not based on program analysis filed in the Proceeding and there is a lack of consistency with BC Hydro industrial DSM offerings (ICG Final Argument, pp. 25–27).

Commission Determination

The Commission Panel accepts the 2014 DSM schedule filed by FBC, attached as Appendix B of this Decision, and approves FBC's request under section 44.2 of the UCA to spend $3.0 million on DSM in 2014. As it is now near the end of 2014, the Panel does not consider that FBC would be able to meaningfully impact its 2014 DSM spend should a higher budget be approved. Therefore, maintaining the applied for $3.0 million is appropriate.

The Commission Panel is encouraged by FBC's statement that it will be working with stakeholders in developing a revised DSM plan. This provides an opportunity to address the concerns raised in the withdrawn filing. The Panel recommends that FBC follow the general principles put forward in the Decision issued with respect to the FEU 2014–2018 EEC Expenditure Request. Specifically, the Panel encourages a focus on its efficiency and cost-effectiveness within the DSM plan while maintaining an appropriate balance in allowing DSM access among ratepayer groups, and in particular for 'hard to reach' customers such as low income groups and renters.

4.2 Other DSM Requests

FBC made the following additional requests:

1. Approval to increase its DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years. FBC submits that the 15-year amortization period is supported by the estimated DSM measure life of 15.9 years. (Exhibit B-1-1, Appendix H, pp. 18-19)

BCSEA and BCOAPO support FBC's position (BCSEA Final Argument, p. 9; BCPSO FBC Non PBR Final Argument, p. 20). ICG, however, is opposed to the increase in amortization period and submits that "it is less expensive for ratepayers to pay for these costs at the time the costs are incurred rather than defer the costs and pay the return at WACC and related income taxes." ICG also recommends that Planning and Evaluation Expenditures be no longer capitalized (ICG Final Argument, p. 32).

2. Approval to cease filing semi-annual reports on its DSM activities (Exhibit B-1-1, Appendix H, p. 19).

BCSEA and BCPSO support FBC's request to submit annual rather than semi-annual DSM Report reports (BCSEA Final Argument, p. 9; BCPSO Non PBR Final Argument, p. 23).

3. Approval of changes to the DSM funding transfer rules set by the Commission for the 2012–2013 test period. Specifically, FBC requests that it be permitted to launch new programs without pre-approval from the Commission provided funds are transferred within the same approved Program Area, the new program meets with the DSM Regulations and has not been previously rejected by the Commission (Exhibit B-1-1, Appendix H, p. 11).

BCSEA supports FBC's request (BCSEA Final Argument, p.9). BCPSO support FBC's request provided DSM funding used to meet DSM Regulations adequacy requirements is not reduced as a result (BCPSO, Non PBR Final Argument, p. 23).

Commission Determination

The Commission Panel denies FBC's request to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years. The Panel considers that a 10-year amortization period provides a fair and reasonable return to the utility based on the existing level of DSM spending, and agrees with ICG that an increase in the amortization period would place upward pressure on rates over the long term.

The Commission Panel accepts FBC's request to submit annual rather than semi-annual DSM Reports as the request is reasonable and has not been opposed by Interveners.

The Commission Panel declines to rule on FBC's proposed DSM funding transfer rules as they are not applicable to the 2014 DSM funding application.

5.0 SUMMARY OF DIRECTIVES DETERMINATIONS AND FINDINGS

This Summary is provided for the convenience of readers. In the event of any difference between the Directions, Determinations and Findings in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Directive	Page
1.	Therefore, the Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.	14
2.	In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.	27
3.	Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.	32
4.	Given these advantages, the Commission Panel determines that the I-Factor used in the formula is the actual index results of the previous year.	33
5.	The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR.	33
6.	The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.	34
7.	The Commission Panel determines that the 55 percent to 45 percent labour to non-labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.	34
8.	The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon.	45
9.	The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend.	46
10.	Accordingly, the Panel finds that B&V's method of calculating the output trend cannot be relied upon.	46
11.	Accordingly, the Panel finds that B&V's method of calculating the input trend cannot be relied upon.	50

12.	Accordingly, the Panel finds that B&V's cost based input methodology understates the TFP trend.	51
13.	The Panel finds that a short study period is not appropriate.	53
14.	Accordingly, the Panel finds that a study period should at least be long enough to smooth out any significant short term economic trends	53
15.	Accordingly, the Commission Panel finds that B&V's TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.	54
16.	Given the materiality of this issue, the Panel finds that B&V's use of arithmetic growth rates results in a substantial understatement of the TFP trend.	55
17.	Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.	56
18.	The Panel finds PEG's approach to using input cost indexes to calculate input quantities is acceptable.	63
19.	In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.	65
20.	The Panel finds that no adjustment to PEG's study results is necessary to account for any potential bias introduced by its labour input index assumptions.	65
21.	The Panel, using its best judgement, finds a reduction of 0.06 percent to the MFP trend results from PEG's gas utility productivity study to be appropriate.	67
22.	Accordingly, the Panel finds that no adjustments are necessary to account for PEG's capital costing approach.	70
23.	Accordingly the Panel declines to make any adjustments to the study results to account for negative salvage.	71
24.	Accordingly, the Panel finds that B&V's proposed calibration is not required.	73
25.	The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding.	78
26.	Accordingly, the Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.	78
27.	Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.	78

<table>
<tr><td>28.</td><td>Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.</td><td>80</td></tr>
<tr><td>29.</td><td>In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study.</td><td>80</td></tr>
<tr><td>30.</td><td>Fortis is directed to report the results of this consultation to the Commission prior to starting the study.</td><td>80</td></tr>
<tr><td>31.</td><td>Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.</td><td>83</td></tr>
<tr><td>32.</td><td>For all of the above reasons, the Panel is unable to approve the X-Factor as applied for.</td><td>87</td></tr>
<tr><td>33.</td><td>Accordingly, if significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.</td><td>87</td></tr>
<tr><td>34.</td><td>The Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.</td><td>87</td></tr>
<tr><td>35.</td><td>Accordingly, the Commission Panel has determined the following X-Factors should be applied to Fortis’ proposed PBR formulas for the PBR term:

Table 5.1 Approved X-Factors
<table>
<tr><th>Utility</th><th>TFP</th><th>Stretch Factor</th><th>X-Factor</th></tr>
<tr><td>FBC</td><td>0.93</td><td>0.1</td><td>1.03</td></tr>
<tr><td>FEI</td><td>0.90</td><td>0.2</td><td>1.10</td></tr>
</table>
</td><td>88</td></tr>
<tr><td>36.</td><td>The Panel finds it necessary to include exogenous factors as part of the Companies’ PBR plan in order to protect both the ratepayers and the shareholders.</td><td>94</td></tr>
</table>

37.	The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment: 1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility; 2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived; 3. The impact of the event was unforeseen; 4. The costs must be prudently incurred; and 5. The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.	94
38.	The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time.	95
39.	The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate.	95
40.	The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.	96
41.	The Commission Panel further directs that exogenous events not be aggregated.	96
42.	Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is, any event resulting in savings must meet the criteria before it is accepted as an exogenous savings.	96
43.	The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.	97
44.	Based on the aforementioned considerations, the Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below.	103
45.	The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense.	103
46.	The Panel directs the Companies to update the flow-through expenses in the Final Compliance Filings so that only the Insurance Premiums are included in the Insurance Expense flow-through.	103–104

47.	The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that the ESM mechanism is not to be applied to flow-through items.	104
48.	The Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.	107
49.	Accordingly, the Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.	108
50.	The Commission Panel directs FBC to true-up these costs each year.	108
51.	Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account.	108–109
52.	For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.	109
53.	The Commission Panel directs FEI to true-up these costs each year	109
54.	Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service line additions two years previous.	118-119
55.	Accordingly, the Commission Panel approved Growth Terms of 0.5 * (SLA_{t-1}/SLA_{t-2}) for FEI's growth capital and 0.5 * (AC_{t-1}/AC_{t-2}) for all other cases.	119
56.	The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers.	120
57.	Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology.	128

58.	Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative; 1. ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year. 2. For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid. 3. Parties will have the opportunity to comment on the proposal.	128
59.	Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs.	134
60.	Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.	135
61.	Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.	143
62.	Within these categories the Commission Panel approves the following SQIs proposed by Fortis: • Safety o Emergency Response Time o Telephone Service Factor (emergency) • Customer needs o First Contact Resolution o Billing Index o Meter Reading Accuracy o Telephone Service Factor (non-emergency) o Meter Exchange Appointment In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include: • Safety	143–144

	o All Injury Frequency Rate o Public Contact with Pipelines • Reliability o SAIDI (weather normalized) FBC only o SAIFI (weather normalized) FBC only Further, the Panel approves the following informational indicators: • Customer Satisfaction Index • Telephone Abandon Rate and we direct Fortis to reinitiate the following informational indicators: • Generator Forced Outage Rate • Transmission Reportable Incidents • Leaks per KM of Distribution System Mains	
63.	The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1, Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further directs that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period.	145–146
64.	The Commission Panel approves the reduction to 70 percent	146
65.	The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.	146
66.	For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark.	146
67.	The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.	146
68.	Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.	149
69.	The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.	149

70.	For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.	150
71.	In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.	150
72.	Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.	150
73.	The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.	151
74.	In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year vary from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years, the off-ramp will be triggered.	155
75.	The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical.	158
76.	Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate.	158
77.	The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope.	170
78.	The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula.	172
79.	In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate.	174
80.	Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.	175

81.	The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended.	178
82.	The Commission directs that the Annual Review process include the following: 1. Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns. 2. Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below: a. Customer growth, volumes and revenues; b. Year-end and average customers, and other cost driver information including inflation; c. Expenses (determined by the PBR formula plus flow-through items); d. Capital expenditures (as determined by the PBR formula plus flow-through items); e. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; f. Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and g. Any proposals for funding of incremental resources in support of customer service and load growth initiatives. 3. Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives (see Section 2.3.2 for a more detailed discussion of the ECM). 4. Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers (see Section 2.2.4 for details). 5. Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service. (see Section 2.3.3.2 for details). 6. Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter	179–180

	Reading Accuracy SQIs. 7. Assess and make recommendations to the Commission on the scope for future Annual Reviews.	
83.	Accordingly, Fortis' request for a Mid-Term Review is denied.	180
84.	The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.	180
85.	FBC is directed to provide an explanation at the next Annual Review as to why this information for past years is unavailable.	182
86.	The Commission Panel determines that an appropriate starting point for the development of the PBR O&M Base is the 2013 Approved O&M.	186
87.	In accordance with FBC's proposed methodology as outlined in BCUC IR 2.90.13, the Panel approves the deferral account and directs that these deferred expenses be treated outside of Base O&M.	195
88.	Accordingly, the Commission Panel determines that a more appropriate addition to the PBR Opening O&M Base to account for first and third party liability expenses is $140,000.	196
89.	The Panel directs that these be excluded from the calculation of the earnings for the purpose of the ESM.	197
90.	Given the background and assurances provided by FBC, the Commission Panel finds that the proposal to include the $350,000 within the Base O&M is reasonable and is not persuaded there is a need to make it a flow through item at this time.	197
91.	In consideration of these factors, the Commission Panel considers that in addition to other directives elsewhere in this Decision, a downward adjustment in the PBR Opening O&M Base is warranted. The Panel, in its best judgement, directs that in addition to the adjustments proposed by FBC a further reduction of $200,000 be made.	198
92.	The Commission Panel accepts that FBC competes for executive talent in the broad spectrum of commercial and industrial organizations. Therefore, FBC's rationale for the choice of the larger, broad-based comparator group is reasonable.	202
93.	The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and reduce its O&M Base accordingly.	203

94.	Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder.	203
95.	As part of its Compliance Filing, FBC is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount that would have been spent if only the target STI had been met (as per page 9 of the Executive Compensation Benchmarking, Exhibit B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M.	203–204
96.	The Commission Panel finds the CEC and ICG arguments to be unpersuasive and puts little weight on them.	209
97.	The Commission Panel approves FBC's 2013 Base Capital as applied for, subject to further adjustment as directed elsewhere in this Decision.	210
98.	Accordingly, the Commission Panel approves discontinuance of the US GAAP to Canadian GAAP reconciliation. The Commission Panel directs FBC to communicate any accounting policy changes/updates to the Commission and other stakeholders as part of its Annual Review process during the PBR period.	212
99.	The Commission Panel approves FBC's request to discontinue the net-of-tax treatment for the pension and OPEB funding differences as applied for.	213
100.	The Panel directs the existing net-of-tax balances of the pension and OPEB to be carried forward as a starting point for 2014, with future additions to both accounts to be on a pre-tax basis and the timing of tax deductions to be recognized in the calculation of income tax expense.	213
101.	FBC's proposed methodology utilizing the Massachusetts Formula is approved.	214
102.	The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.	214
103.	the Panel approves FBC to continue its Transmission and Distribution direct overhead loading allocation during the PBR period.	216
104.	The Panel directs FBC to reduce its capitalized overhead rate to 15 percent in 2014.	218
105.	The Commission Panel agrees and also considers it inappropriate for FBC to capitalize these recurring fees and directs FBC to expense its annual software costs in a manner consistent with the direction provided to FEI by the Commission in Section 3.2.3 of the FEI 2014–2018 PBR RRA Decision.	219

106.	As part of its Compliance Filing, FBC is directed provide the following information: (i) the total amount paid in 2013 for annual software costs; (ii) the amounts originally included in FBC's Application for 2013 Base O&M and 2013 Base Capital related to annual software costs; and (iii) the increase to FBC's 2013 Base O&M as a result of this change in treatment of annual software costs and the resulting decrease to FBC's 2013 Base Capital.	219
107.	The Commission Panel denies FBC's proposal to establish the RSDM combining the impact of WAX CAPA and other PBR rate impacts.	224
108.	In its Compliance Filing, FBC must recalculate and show the 2014 revenue requirement and rate impact without the rate smoothing effect of the RSDM. FBC must also propose to the Commission a method to treat the revenue requirement impact between the interim rate increase approved under Order G-151-13 and the rate resulting from this Decision.	224–225
109.	The Commission Panel approves FBC's proposal to establish an ESM deferral account.	225
110.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be at FBC's short-term interest rate.	225
111.	The Commission Panel approves the establishment of the BC Hydro Application for New PPA with FBC deferral account as applied for by FBC.	226
112.	However, the Commission Panel directs FBC to update its forecast addition to the deferral account as it relates to the Written Hearing as part of its Compliance Filing.	226
113.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with FBC's 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate (p. 105).	226
114.	The Commission Panel approves the establishment of the GCOC Revenue Requirements Impact deferral account.	227
115.	The Panel also determines that the carrying cost allowed on this deferral account shall be aligned with the FBC 2012–2013 RRA Decision as outlined in Section 3.3.1 and shall be FBC's short-term interest rate.	227
116.	The Commission Panel approves the establishment of the 2014–2018 Annual Reviews Deferral Account.	227

117.	Accordingly, the Panel directs FBC to discontinue the Power Purchase Expense deferral account and its related Revenue Variance deferral account during the PBR term. These expenses and revenues shall be flowed through to ratepayers each year through the annual flow-through mechanism.	228
118.	In its Compliance Filing, FBC is directed to provide its 2013 ending balances in these deferral accounts and illustrate the rate impact of flowing through these variances to 2014 rates. Variances between FBC's forecast and actual results in 2014 and beyond shall to be flowed through to ratepayers annually.	229
119.	The Commission Panel approves the establishment of the non-rate base CPCN Projects Preliminary Engineering deferral account	230
120.	The Commission Panel rejects FBC's proposal to apply AFUDC to this new deferral account	230
121.	The Panel directs FBC to comply with the previous Commission decision and apply carrying costs based on FBC's WACD to this deferral account starting in 2014.	230
122.	The Commission Panel approves the amortization of the 2014–2018 PBR Application deferral account over six years commencing January 1, 2014.	232
123.	The Commission Panel denies FBC's request to change the Pension & OPEB Expense Variance deferral account amortization period from three years to the EARSL. FBC must therefore continue amortizing this deferral account over three years.	233
124.	The Commission Panel approves the amortization of both the City of Kelowna Acquisition Customer Benefit deferral account and the City of Kelowna Acquisition Legal and Regulatory Costs deferral account over one year, commencing January 1, 2014.	234
125.	The Panel directs that these deferral accounts be discontinued effective January 1, 2015, as proposed by FBC in the Application.	234
126.	The Commission Panel approves FBC's request to amortize the 2014–2018 Capital Expenditure Plan deferral account over two years.	234
127.	the Commission Panel grants approval to FBC to establish a new deferral account to transfer the costs associated with the GCOC proceeding from the holding account to a separate deferral account for recovery from ratepayers. The Panel also approves the requested two-year amortization period, commencing in 2014.	236
128.	The Panel denies FBC's request to charge a WACC carrying charge to this deferral account	236

129.	The Commission Panel directs FBC to apply its WACD to this deferral account. FBC shall also apply its WACD to calculate the carrying charges on the 2013 balance.	236
130.	FBC's requested deferral account for the BCUC Inquiry into the MRS Program and its requested amortization period of one year beginning in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.	236
131.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account to calculate the carrying charges on the 2013 balance.	236
132.	Given these circumstances, the Commission Panel finds that it is also reasonable to approve FBC's (legal) costs related to this inquiry. Accordingly, the Panel approves FBC's request to establish the Kettle Valley Expenditure Review deferral account with the amortization period of one year, starting in 2014. The Panel denies FBC's request to apply WACC to the deferral account.	236–237
133.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC is directed to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	237
134.	Given these circumstances, FBC's deferral of the cost for the Transmission Customer Rate Design review and its requested amortization period of one year commencing in 2014 are approved. The Panel denies FBC's request to apply WACC to the deferral account.	237
135.	The Commission Panel directs FBC to apply its short-term interest rate to this deferral account. FBC shall also apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	237
136.	The Panel approves FBC's request for deferral of the incremental 2012 MRS costs with an amortization period of one year commencing in 2014. However, the Panel denies FBC's request to apply WACC to the deferral account.	237-238
137.	The Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	238
138.	In its Compliance Filing, FBC must confirm that these MRS audit expenses were not included in its proposed O&M base. To the extent that these MRS audit costs are included in the O&M base, they must be removed.	238
139.	The Panel approves the incremental costs ($0.3 million for 2012 and $0.9 million for 2013) related to its MRS O&M expense. The Panel grants approval for FBC to amortize these deferred costs into rates in 2014. The Panel denies FBC's request to apply WACC to the deferral account.	238

140.	The Commission Panel directs FBC to apply its short-term interest rate to calculate the carrying charges on the 2013 balance.	238
141.	The Commission Panel approves the treatment of the deferred debt issue costs as applied for by FBC.	239
142.	The Commission Panel approves FBC's request to discontinue the deferral accounts listed in Table 3.11 above, and as outlined in the Application and in its Evidentiary Update.	241
143.	The Commission Panel accepts the 2014 DSM schedule filed by FBC, attached as Appendix B of this Decision, and approves FBC's request under section 44.2 of the UCA to spend $3.0 million on DSM in 2014.	242
144.	The Commission Panel denies FBC's request to increase the DSM amortization period and amortization of the On-Bill Financing Pilot Program from 10 years to 15 years.	244
145.	The Commission Panel accepts FBC's request to submit annual rather than semi-annual DSM Reports.	244
146.	The Commission Panel declines to rule on FBC's proposed DSM funding transfer rules as they are not applicable to the 2014 DSM funding application.	244

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September 2014.

Original signed by:

____
D.A. COTE
PANEL CHAIR/COMMISSIONER

Original signed by:

____
N.E. MACMURCHY
COMMISSIONER

Original signed by:

____
D.M. MORTON
COMMISSIONER

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

and

FortisBC Inc.
Application for Approval of a
Multi-Year Performance Based Ratemaking Plan
for the years 2014 through 2018

BEFORE: D.A. Cote, Panel Chair/Commissioner
D.M. Morton, Commissioner
N.E. MacMurchy, Commissioner September 15, 2014

O R D E R

WHEREAS:

A. On July 5, 2013, FortisBC Inc. (FBC) applied to the British Columbia Utilities Commission (Commission) for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014 through 2018 (Application);

B. Among other things, FBC's Application includes the following requests, under section 59-61 of the *Utilities Commission Act* (UCA):

a. to make its interim rates at that time be permanent, effective January 1, 2013, and to increase the permanent rates for all customers by 3.3 percent, effective January 1, 2014;

b. a rate stabilization mechanism for the years 2014 to 2018;

c. the flow through, during 2014, of any increase or decrease arising from the Generic Cost of Capital Stage 2 proceeding;

d. certain accounting treatment and financing of deferral accounts;

e. certain accounting policies changes to be used in the determination of rates effective January 1, 2014; and

f. approval of a proposed PBR mechanism for setting rates during the years 2014 to 2018;

C. FBC also seeks acceptance of certain Demand-Side Management expenditures and changes, pursuant to section 44.2 of the UCA;

D. On July 25, 2013, FBC held a Workshop in Kelowna, BC to review the Application;

E. On September 5, 2013, a Procedural Conference was held jointly with FBC's affiliate, FortisBC Energy Inc. (FEI), who has also applied for a PBR plan with the Commission. The Procedural Conference considered the regulatory process for both the FEI and FBC Applications and the possibility of combining some parts or all of the two proceedings;

F. By Orders G-151-13, the Commission amended the Regulatory Timetables and established that an Oral Hearing to review PBR related issues be held jointly with FEI. The Commission also approved a 3.3 percent interim and refundable rate increase for FBC, effective January 1, 2014;

G. The Regulatory Timetables for review of the Application was further amended by Orders G-206-13, G-219-13, G-8-814, and G-10-14;

H. The Oral Hearing on PBR related issues commenced on March 10, 2014 and was completed on March 18, 2014;

I. Between April 25 and May 22, 2014, FBC and Interveners filed their Final Arguments on both PBR related and non-PBR issues. On June 12, 2014, FBC filed it Reply Arguments.

J. A Commission Panel Information Request was issued on June 19, 2014 with an accompanying timetable for completion;

K. On July 14, 2014, the Commission Panel held the Oral Argument Phase to address the Panel Information Requests, its related responses and certain topics identified by the Panel;

L. The Commission has considered the FBC Application, the evidence and submissions by all parties in this proceeding and provides its Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the *Utilities Commission Act,* the Commission Panel makes the following determinations:

    a. The rate stabilization mechanism is denied;

    b. Rates effective January 1, 2013 are to be made permanent;

c. Approval to flow-through the revenue requirement impact as a result of the decrease in the return on equity that was used to calculate its rates effective January 1, 2013 is granted; and

d. A PBR mechanism in setting rates for the period of 2014 to 2019 is approved, subject to the various amendments outlined in the Decision.

2. Pursuant to section 44.2(3) of the *Utilities Commission Act*:

   a. The Demand-Side Management (DSM) expenditure, up to $3.0 million for 2014, is accepted;

   b. The proposal to change the amortization period of existing and future DSM expenditures from 10 years to 15 years is denied; and

   c. The proposal to discontinue the semi-annual reporting on its DSM program and to submit annual reports at the end of each calendar year, effective January 1, 2014 is accepted.

3. FortisBC Inc. is directed to submit a Compliance Filing to the Commission, within 60 days of this Order, with amended financial schedules that incorporate all the adjustments and directives as outlined in the Decision. FortisBC Inc. must also propose a method to treat the difference between the 2014 interim rate and the rate approved in this Decision.

4. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules that conform to the Decision.

5. FortisBC Inc. is to notify all customers, by way of an information notice, of the change in rates.

6. FortisBC Inc. must comply with all other directives contained in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September of 2014.

BY ORDER

Original signed by:

D.A. Cote
Commissioner/Panel Chair

Regulatory Process Summary

On August 23, 2013, the Commission issued a letter to all parties in both Applications suggesting combining the two applications for the purpose of dealing with the PBR elements of the two applications jointly. At a joint Procedural Conference, held on September 5, 2013, all parties agreed.

On September 12, 2013, the Commission Panel issued Order G-151-13 ordering a joint Oral Hearing on the PBR methodology for both FEI and FBC. All other matters were to be reviewed by separate Written Hearings.

There were two rounds of Information Requests (IRs) with the second round broken out into those questions concerning PBR methodology and those dealing with non PBR issues.

Further amendments to the Regulatory Timetable were made through Orders G-206-13, G-219-13, G-8-14, and G-10-14.

The Oral Hearing on PBR Issues commenced on March 10, 2014, and was completed on March 18, 2014.

FEI and FBC filed a joint Final Argument on the PBR issues on April 25, 2014. FBC's Final Argument for non PBR issues was received on April 28, 2014. Final Arguments from all Interveners were received by May 22, 2014, and the FBC Reply Argument (Non PBR Issues) and Fortis Joint Reply Argument (PBR issues) were received on June 12, 2014.

A Panel Information Request and request for additional submissions was issued on June 19, 2014 with an accompanying timetable for completion.

On July 14, 2014, the Commission Panel held a hearing to receive oral argument on the Panel IRs, related responses and the Panel's additional topics issued June 27, 2014.

Summary Table of FortisBC 2014–2018 DSM Plan

1	Program Area	Plan Savings (MWh/year)					Plan Cost $(000s)					Benefit/Cost Ratios			
2		2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	TRC	mTRC	Utility	Part
3	**Programs by Sector**														
4	Residential	5,800	5,783	5,615	5,511	5,407	1,037	1,081	1,008	1,015	1,024	1.2	1.3	3.5	
5	General Service	6,200	6,304	6,408	6,512	6,616	1,134	1,166	1,195	1,223	1,256	1.4	1.7	3.3	
6	Industrial	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	
7	**Sub-total Programs:**	**12,800**	**12,887**	**12,823**	**12,823**	**12,823**	**2,319**	**2,397**	**2,355**	**2,392**	**2,436**	**1.4**	**1.5**	**3.9**	
8	Supporting Initiatives						190	190	190	190	190				
9	Planning & Evaluation						492	500	509	518	527				
10	Total (incl. Portfolio):						**3,001**	**3,087**	**3,054**	**3,100**	**3,153**	**1.2**	**1.4**	**3.7**	
11	**Residential Programs**														
12	Building Envelope	1,881	1,881	1,881	1,881	1,881	295	299	301	305	308	1.1	1.3	4.8	
13	Heat Pumps	553	553	553	553	553	158	159	161	163	164	1.1	1.1	2.4	
14	Lighting	2,136	2,067	1,997	1,928	1,859	176	171	164	158	153	1.4	1.4	5.9	
15	New Home	98	98	98	98	98	67	68	68	69	70	0.6	1.2	1.2	
18	Water heating	425	440	455	470	485	99	103	108	112	119	1.6	1.9	2.1	
19	Low Income & Rental	707	744	631	581	531	242	281	206	208	210	0.8	0.8	1.0	
21	**Total**	**5,800**	**5,783**	**5,615**	**5,511**	**5,407**	**$ 1,037**	**$ 1,081**	**$ 1,008**	**$ 1,015**	**$ 1,024**	**1.2**	**1.3**	**3.5**	
22	**General Service Programs**														
23	Lighting	3,359	3,463	3,567	3,671	3,775	510	535	557	579	603	1.7	2.0	3.4	
24	BIP	2,641	2,641	2,641	2,641	2,641	592	598	605	611	619	1.1	1.5	3.1	
27	Irrigation	200	200	200	200	200	32	33	33	33	34	2.1	2.1	7.3	
28	**Total**	**6,200**	**6,304**	**6,408**	**6,512**	**6,616**	**$ 1,134**	**$ 1,166**	**$ 1,195**	**$ 1,223**	**$ 1,256**	**1.4**	**1.7**	**3.3**	
29	**Industrial Programs**														
31	Ind Efficiency	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	
32	**Total**	**800**	**800**	**800**	**800**	**800**	**$ 148**	**$ 150**	**$ 152**	**$ 154**	**$ 156**	**2.8**	**2.8**	**5.7**	

(Source: Exhibit B-1-1, Appendix H, Attachment 1, p. 14)

AFUDC	Allowance for Funds Used During Construction
AIFR	All Injury Frequency Rate
AMI	Advanced Metering Infrastructure
Application	Multi-Year Performance Based Ratemaking Plan for the Years 2014 through 2018 Including Approval of Rates for 2014 in Accordance with the PBR Plan
ARM	Attrition Relief Mechanism
AUC	Alberta Utilities Commission
B&V	Black and Veatch
BC Hydro	British Columbia Hydro and Power Authority
BC-CPI	British Columbia Consumer Price Index
BCMEU	British Columbia Municipal Electrical Utilities
BCPSO	British Columbia Pensioners’ and Seniors’ Organization
BCSEA	BC Sustainable Energy Association and the Sierra Club of British Columbia
Capex	Capital Expenditures
CEA	*Clean Energy Act*
CEC	Commercial Energy Consumers of British Columbia
CGA	Canadian Gas Association
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union Local 378
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity

CPI	Consumer Price Index
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation (BC Reg. 326/2008)
EARSL	Expected Average Remaining Service Life
ECI	Employment Cost Index
ECM	Efficiency Carry-Over Mechanism
ESM	Earnings Sharing Mechanism
EUCPI	Electric Utility Construction Price Index
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
Fortis	FortisBC Energy Inc. and FortisBC Inc.
GAAP	Generally Accepted Accounting Principles
Gabana	Gabana, Norman
GCOC	Generic Cost of Capital
GWh	Gigawatt hour
Hay	Hay Group Limited
IBEW	International Brotherhood of Electrical Workers
ICG	Industrial Consumers Group
IFRS	International Financial Reporting Standards
IRG	Irrigation Ratepayers Group
IRs	Information Requests
ISP	Integrated System Plan
IT	Information Technology

KORP	Kingsvale-Oliver Reinforcement Project
LFTC	Load Forecast Technical Committee
LRMC	Long-Run Marginal Cost
M&S	Materials and Services
MEM	Ministry of Energy and Mines
MFP	Multifactor Productivity
MFP^N	Multifactor Productivity Index
MRS	Mandatory Reliability Standards
mTRC	modified TRC
MWh	Megawatt hour
NERA	National Economic Research Associates
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
O&M	Operating and Maintenance
OEB	Ontario Energy Board
OPEB	Other Post-Employment Benefits
Opex	Operating & Maintenance Expenditure
PBR	Performance Base Ratemaking
PBR Plan	Multi-Year Performance Based Ratemaking Plan for the Years 2014 through 2018
PIF	Productivity Improvement Factors
PPA	Power Purchase Agreement
Rate Schedule 1	Residential Conservancy Rate
RNG	Renewable Natural Gas

ROE	Return on Equity
RRA	Revenue Requirements Application
RS 3808	BC Hydro Application for a Power Purchase Agreement with FBC
RSDM	Rate Stabilization Deferral Mechanism
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Southern Crossing Pipeline
SQIs	Service Quality Indicators
Stanski	Stanski, Henry
STIP	Short Term Incentive Plan
T&D	Transmission and Distribution
TFP	Total Factor Productivity
TRC	Total Resource Cost
UCA	*Utilities Commission Act*
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAX CAPA	Waneta Capacity Purchase Agreement

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

and

FortisBC Inc.
Application for Approval of a
Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated July 10, 2013 – Appointment of Commission Panel
A-2	Letter Dated July 17, 2013 – Order G-109-13 Establishing a Preliminary Regulatory Timetable, Procedural Conference and Notice of Workshop
A-3	Letter Dated August 14, 2013 - Commission Information Request No. 1 to FortisBC Inc.
A-3-1	Letter Dated August 15, 2013 – Reformatted Commission Information Request No. 1 to FortisBC Inc.
A-4	**CONFIDENTIAL** Letter Dated August 14, 2013 - Commission Confidential Information Request No. 1 to FortisBC Inc.
A-5	Letter Dated August 23, 2013 – Commission Acceptance of CEC's late Information Request
A-6	Letter Dated August 23, 2013 – Commission Acceptance of Mr. Stanski's late Information Request
A-7	Letter Dated August 23, 2013 – Proposed Change to Procedural Conference
A-8	Letter Dated August 23, 2013 – BCUC Requesting Comments on COPE 378's Late Supplemental Information Request
A-9	Letter Dated August 29, 2013 – Order G-133-13 issuing a Revised Preliminary Regulatory Timetable

A-10	Letter Dated August 30, 2013 – BCUC issuing Procedural Conference Items
A-11	Letter Dated September 4, 2013 – Order G-139-13 directing FortisBC Inc. to respond to COPE 378's Supplemental Information Requests
A-12	Letter Dated September 10, 2013 – Appointment of Commissioner MacMurchy
A-13	Letter Dated September 13, 2013 – Order G-151-13, amending the Regulatory Timetable
A-14	Letter Dated October 4, 2013 – BCUC Requesting comments on Gabana C7-3 submission
A-15	Letter Dated October 4, 2013 – Order G-165-13 Amending the Regulatory Timetable
A-16	Letter Dated October 16, 2013 – Response to Mr. Gabana's complaint
A-17	Letter Dated October 25, 2013 – Commission Information Request No. 2 on all non-Performance Based Rates Methodology issues
A-18	Letter Dated November 8, 2013 – Commission Information Request No. 2 on Performance Based Rates Methodology issues
A-19	Letter Dated November 25, 2013 – Response to FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2
A-20	Letter Dated December 2, 2013 – Order G-206-13 Amending the Regulatory Timetable
A-21	Letter L-73-13 Dated December 12, 2013 – BCUC Response to COPE letter
A-22	Letter Dated December 18, 2013 – Order G-219-13 Amending the Regulatory Timetable
A-23	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCPSO on Intervener Evidence
A-24	Letter Dated January 16, 2014 – Commission Information Request No. 1 to COPE 378 on Intervener Evidence
A-25	Letter Dated January 16, 2014 – Commission Information Request No. 1 to CEC on Intervener Evidence

A-26	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCSEA on Intervener Evidence
A-27	Letter Dated January 16, 2014 – Commission Information Request No. 1 to ICG on Intervener Evidence
A-28	Letter Dated January 16, 2014 – Commission Order G-8-14 Amending the Regulatory Timetable
A-29	Letter Dated January 16, 2014 – Commission Letter L-3-14 Providing Scope of Oral Hearing
A-30	Letter Dated January 23, 2014 – Commission Order G-10-14 Amending the Regulatory Timetable
A-31	Letter Dated February 12, 2014 – Commission Information Request No. 2 to BCPSO on Intervener Evidence
A-32	Letter Dated February 12, 2014 – Commission Information Request No. 2 to CEC on Intervener Evidence
A-33	Letter Dated February 12, 2014 – Commission Information Request No. 2 to ICG on Intervener Evidence
A-34	Letter Dated February 19, 2014 – Oral Hearing Information
A-35	Letter Dated February 28, 2014 – CEC IR Response Request for Submission
A-36	Letter Dated March 4, 2014 – Panel's decision on certain CEC's IR responses
A-37	Letter Dated March 10, 2014 – Commission Information Request No. 2 to BCSEA
A-38	Letter Dated March 18, 2014 – Final Submissions Regulatory Timetable
A-39	Letter Dated March 27, 2014 – Commission Information Request No. 1 to FBC on FBC Rebuttal Evidence
A-40	Letter Dated April 30, 2014 – Request for comments on CEC's Request for an Extension of the Deadline for Filing of Argument by Interveners
A-41	Letter Dated April 30, 2014 – Recusal of B. Magnan from Panel

A-42 Letter Dated May 8, 2014 – Response to CEC Request for Extension

A-43 Letter Dated June 19, 2014 – Panel Information Request No. 1, Oral Argument and Timetable

A-44 Letter Dated June 27, 2014 – Commission Submitting Oral Argument Topics

A-45 Letter Dated July 10, 2014 – Commission Submitting Oral Argument Clarification

COMMISSION STAFF DOCUMENTS

A2-1 Letter dated August 14, 2013 – Commission Staff filing FortisBC Inc. 2012–13 Revenue Requirements and 2012 Integrated System Plan Order G-110-12 Directive 10 Workforce Action Plan

A2-2 Letter dated August 14, 2013 – Commission Staff filing Commission Staff filing FortisBC Inc. 2012 US GAAP Appendix A – Reconciliation of Financial Statements

A2-3 Letter dated August 14, 2013 – FortisBC Inc. 2012 Application for Approval to Establish Deferral Accounts

A2-4 Letter dated August 14, 2013 – Commission Staff filing FortisBC Holdings Inc. – Statement of Executive Compensation

A2-5 Letter dated August 14, 2013 – Commission Staff filing Ontario Ministry of Energy Agency Review, May 2007

A2-6 Letter dated August 14, 2013 – Commission Staff filing Hydro Ottawa Holding Inc. 2011 Annual Report

A2-7 Letter dated August 14, 2013 – Commission Staff filing Toronto Hydro Corporation 2012 Annual Information Form

A2-8 Letter dated August 14, 2013 – Commission Staff filing Nova Scotia Power 2013 Management Information Circular

A2-9 Letter dated August 14, 2013 – Commission Staff filing Statistics Canada - CANSIM Table 282-0012 Labour force survey estimates, employment by class of worker, North American Industry Classification System and sex annual

A2-10 Letter dated August 14, 2013 – Commission Staff filing Aligning Utility Incentives with Investment in Energy Efficiency A Resource of the National Action Plan for Energy Efficiency, November 2007

A2-11 Letter dated August 14, 2013 – Commission Staff filing International Energy Agency Insights Series 2013 Energy Provider-Delivered Energy Efficiency

A2-12 Letter dated September 4, 2013 – Commission Staff Submissions for the September 5, 2013 Procedural Conference

A2-13 Letter dated October 25, 2013 – Commission Staff filing Pacific Institute for Climate Solutions, September 30, 2013 Media Release: British Columbia should prepare for a different climate future

A2-14 Letter dated October 25, 2013 – Commission Staff filing web article by IT developer – Habanero Consulting Group for Enterprise Solution

A2-15 Letter dated October 25, 2013 – Commission Staff filing American Council for an Energy-Efficient Economy — Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs (September 2009 Report)

A2-16 Letter dated October 25, 2013 – Commission Staff filing BC Hydro Integrated Resource Plan 2013

A2-17 Letter dated October 25, 2013 – Commission Staff filing Navigant Consulting — Review of the Efficiency Maine Trust Triennial Plan (2011–2013)

A2-18 Letter date November 8, 2013 – Commission Staff filing Business Council of British Columbia – Productivity: BC's Position and Why We Should Care

A2-19 Letter date November 8, 2013 – Commission Staff filing Special Report – TD Economics – Estimating Longer-Term Growth Prospects in Canada's Provincial Economies

A2-20 Letter date November 8, 2013 – Commission Staff filing Excerpt from Ontario Energy Board Staff Report to the Board on Performance Measurement and Continuous Improvement for Electricity Distributors

A2-21 Letter date November 8, 2013 – Commission Staff filing Report from the 9th International Conference on Probabilistic Methods Applied to Power Systems — Utilizing Bulk Electric System Reliability Performance Index Probability Distributions in a Performance Based Regulation Framework

A2-22 Submitted at Oral Hearing March 12, 2014 – FortisBC and FortisBC Energy Inc. 2014-2018 Performance Based Rates – Staff Witness Aids

A2-23 Submitted at Oral Hearing March 12, 2014 – FortisBC/FEI 2014-20918 PBR Witness Aid - Inflation

A2-24 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Witness Aid - St. Additions

A2-25 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FBC Scenario 1

A2-26 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FEI Scenario 1

A2-27 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – ECM, with Cover Page re. Scenarios 1 and 2

A2-28 Submitted at Oral Hearing March 13, 2014 – Extract from Decision of Ontario Energy Board in the Matter of an Application by Enbridge Gas Distribution

A2-29 Submitted at Oral Hearing March 14, 2014 - FBC/FEI 2014-2018 PBR Staff Witness Aid - COPE

A2-30 Submitted at Oral Hearing March 17, 2014 – Response to BCUC Information Request No. 1, Page 161, Submission date September 20, 2013

APPLICANT DOCUMENTS

B-1 **FORTISBC INC. (FBC)** Letter Dated July 5, 2013 - Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 Volume 1

B-1-1 Letter Dated July 5, 2013 – FBC Submitting Application Appendices Volume 2

B-1-2 **CONFIDENTIAL** Letter Dated July 5, 2013 – FBC Submitting Confidential page 120

B-1-3	**CONFIDENTIAL** Letter Dated July 5, 2013 – FBC Submitting Confidential Appendix C2
B-1-4	Letter Dated July 25, 2013 – FBC Submitting Errata 1 to the Application
B-1-5	Letter dated September 20, 2013 – FBC Submitting Errata 2 to the Application
B-1-6	Letter dated October 18, 2013 – Evidentiary Update to the Application
B-1-7	Letter Dated December 5, 2013 - FBC Submitting Errata 3 to 2014-18 PBR Plan Application and Responses to BCUC IR No. 1
B-1-8	Letter Dated December 13, 2013 – FBC Submitting Errata 4 Appendix D2
B-1-9	Letter Dated July 16, 2014 - FBC Submitting Application Amendment DSM Expenditure Request
B-2	Letter Dated July 25, 2013 – FBC Submitting Workshop Presentation
B-3	Letter Dated August 22, 2013 – FBC Submitting Response to COPE 378 Late Supplemental Information Requests
B-4	Letter Dated August 27, 2013 – FBC Submitting Further Response for Comment on COPE 378's Late Supplemental Information Request
B-5	Letter Dated September 4, 2013 - FBC Submissions for the September 5, 2013 Procedural Conference
B-6	Letter dated September 20, 2013 – FEI-FBC Joint Procedural Conference Response to Undertaking
B-7	Letter Dated September 20, 2013 - FBC Response to BCUC IR No. 1
B-7-1	**CONFIDENTIAL** Letter Dated September 20, 2013 - FBC Response to BCUC IR1 Confidential Attachments 220.1 and 222.1
B-8	**CONFIDENTIAL** Letter Dated September 20, 2013 - FBC Response to BCUC Confidential IR No. 1
B-9	Letter Dated September 20, 2013 - FBC Response to BCMEU IR No. 1
B-9-1	**CONFIDENTIAL** Letter Dated September 20, 2013 - FBC Response to BCMEU IR No. 1 Confidential Attachments

B-10 Letter Dated September 20, 2013 - FBC Response to CEC IR No. 1

B-10-1 **CONFIDENTIAL** Letter Dated September 20, 2013 - FBC Response to CEC IR No. 1 Confidential Attachments

B-11 Letter Dated September 20, 2013 - FBC Response to BCPSO IR No. 1

B-12 Letter Dated September 20, 2013 - FBC Response to BCSEA IR No. 1

B-13 Letter Dated September 20, 2013 - FBC Response to COPE IR No. 1

B-14 Letter Dated September 20, 2013 - FBC Response to Gabana IR No. 1

B-15 Letter Dated September 20, 2013 - FBC Response to ICG IR No. 1

B-16 Letter Dated September 20, 2013 - FBC Response to Stanski IR No. 1

B-17 Letter dated September 24, 2013 – FEI-FBC Response to COPE Request to Amend Timetable

B-18 Letter dated September 27, 2013 – FBC Response to COPE Supplementary IR No. 1

B-19 Letter Dated October 7, 2013 – FBC Response to Mr. Gabana

B-20 Letter Dated November 22, 2013 – FBC Notice of Delay filing responses to BCUC IR No. 2 and CEC IR No. 2

B-21 Letter Dated November 22, 2013 – FBC Response to BCSEA IR No. 2

B-22 Letter Dated November 22, 2013 – FBC Response to ICG IR No. 2

B-23 Letter Dated November 22, 2013 – FBC Response to BCPSO IR No. 2

B-24 Letter Dated November 26, 2013 – FBC Response to BCUC IR No. 2

B-24-1 **CONFIDENTIAL** Letter Dated November 26, 2013 – FBC Response to BCUC IR No. 2 Confidential Attachment 77.2.1

B-25 Letter Dated November 26, 2013 – FBC Response to CEC IR No. 2

B-26 Letter Dated November 29, 2013 – FBC Submitting Comments Regarding Regulatory Timetable

B-27 Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR2a - Non PBR Methodology

B-28 Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR2a - Non PBR Methodology

B-29 Letter Dated December 6, 2013 - FEI-FBC Response to COPE IR2A - Non PBR Methodology

B-30 Letter Dated December 11, 2013 - FEI-FBC Response to COPE Letter

B-31 Letter Dated December 17, 2013 - FEI-FBC Response to Requests for Extensions to the Regulatory Timetable for Intervener Evidence

B-32 Letter Dated January 6, 2014 – FEI-FBC Rebuttal Evidence Confirmation

B-33 Letter Dated January 13, 2014 – FBC Submission on the Remainder of the Regulatory Timetable

B-34 Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCPSO

B-35 Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCSEA

B-36 Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to CEC

B-37 Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to COPE

B-38 Letter Dated February 12, 2014 – FEI-FBC Submitting IR No. 2 to CEC on Intervener Evidence

B-39 Letter Dated February 27, 2014 – FEI-FBC Submitting Objection to CEC IR Responses on Capital Tracker Mechanism

B-40 Letter Dated February 28, 2014 – FEI-FBC Submitting Witness Panels, Direct Testimony and Notice of Cross Examination

B-41	Letter Dated March 3, 2014 – FEI-FBC Submitting Reply regarding Request to Strike CEC IRs
B-42	Letter Dated March 3, 2014 – FBC Submitting Rebuttal Evidence to BCSEA
B-43	Letter Dated March 3, 2014 – FBC Submitting Rebuttal Evidence to ICG
B-44	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to BCPSO
B-45	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to CEC and COPE
B-46	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to COPE
B-47	Letter Dated March 7, 2014 – FEI-FBC Submitting Opening Statement Presentation
B-48	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Testimony of Dr. H. Edwin Overcast, Black & Veatch to CEC
B-48-1	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Evidence to CEC
B-49	Letter Dated April 11, 2014 - FBC Response to BCSEA IR No. 1 on FBC Rebuttal Evidence
B-50	Letter Dated April 11, 2014 - FBC Response to BCUC IR No. 1 on FBC Rebuttal Evidence
B-51	Letter Dated April 11, 2014 - FBC Response to CEC IR No. 1 on FBC Rebuttal Evidence
B-52	Letter Dated April 29, 2014 - FEI-FBC Submitting Objection to CEC Request for Extension
B-53	Letter Dated June 27, 2014 - FEI-FBC Responses to Panel Information Request No. 1
B-54	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Request for Procedural Confirmation
B-55	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Procedural Confirmation Reply
B2-1	Letter Dated December 6, 2013 - FEI Response to BCUC IR3a - PBR Methodology

B2-2	Letter Dated December 6, 2013 - FEI Response to CEC IR3a - PBR Methodology
B2-3	Letter Dated December 6, 2013 - FBC Response to BCUC IR3a - PBR Methodology
B2-4	Letter Dated December 6, 2013 - FBC Response to BCPSO IR3a - PBR Methodology
B2-5	Letter Dated December 6, 2013 - FBC Response to BCSEA IR3a - PBR Methodology
B2-6	Letter Dated December 6, 2013 - FBC Response to CEC IR3a - PBR Methodology
B2-7	Letter Dated December 6, 2013 - FBC Response to ICG IR3a - PBR Methodology
B2-8	Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR3 – PBR Methodology
B2-9	Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR3 – PBR Methodology
B2-10	Letter Dated December 6, 2013 -FEI-FBC Response to BCSEA IR3 – PBR Methodology
B2-11	Letter Dated December 6, 2013 -FEI-FBC Response to CEC IR3 – PBR Methodology
B2-12	Letter Dated December 6, 2013 -FEI-FBC Response to CEC Supplemental IR3 – PBR Methodology
B2-13	Letter Dated December 6, 2013 -FEI-FBC Response to COPE IR3 – PBR Methodology
B2-13-1	Letter Dated December 11 2013 - FEI-FBC Response to COPE Letter IR 3.G.14
B2-14	Letter Dated December 6, 2013 -FEI-FBC Response to ICG IR3 – PBR Methodology
B2-15	Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 1 re. Volume 2, Page 362, Line 6 to Page 364, Line 20
B2-16	Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 2 re. Volume 2, Page 293, Line 25 to Page 296, Line 5
B2-17	Submitted at Oral Hearing March 12, 2014 – Empirical Research In Support Of Incentive Rate Setting, 2012 Update, Report to the Ontario Energy Board Dated September, 2013 by Pacific Economics Group Research

B2-18 Submitted at Oral Hearing March 13, 2014 – FortisBC Undertaking No. 3 re. Volume 2, Page 357, Line 5 to Page 358, Line 7

B2-19 Submitted at Oral Hearing March 13, 2014 – FortisBC Undertaking No. 4 re. Volume 3, Page 406, Line 20 to Page 407, Line 217

B2-20 Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 5 re. Volume 4, Page 603, Lines 16 to 24

B2-21 Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 6 re. Volume 4, Page 606, Lines 13 to 23

B2-22 Submitted at Oral Hearing March 14, 2014 – "FortisBC Materials for Cross-Examination of Ms. Barbara Alexander (COPE)"

B2-23 Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 7 re. Volume 4, Page 607, Lines 4 to 14

B2-24 Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 8 re. Volume 4, Page 822, Lines 5 to 16

B2-25 Submitted at Oral Hearing March 14, 2014 - FortisBC Undertaking No. 9 re. Volume 4, Page 674, Line 17 to Page 674, Line 14

B2-26 Submitted at Oral Hearing March 17, 2014 - Evidence Of Russ Bell

B2-27 Submitted at Oral Hearing March 18, 2014 - FortisBC Materials For Cross-examination of Dr. Mark Lowry (CEC)"

B2-28 Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 10 re. Volume 6, Page 1160, Lines 21 to 26

B2-29 Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 11 re. Volume 6, Page 1162, Lines 5 to 14

B2-30 Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 12 re. Volume 6, Page 1249, Line 20 to Page 1250, Line 19

B2-31 Submitted at Oral Hearing March 18, 2014 - **CONFIDENTIAL** - "Cost Trends of Gas Utility Construction, Cost Trend Tables 1912 to July 1, 2013" from Handy-Whiteman

B2-32 Submitted at Oral Hearing March 18, 2014 - Excel Spreadsheet

B2-33 Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 13 re. Volume 6, Page 1266, Lines 10 to 21

B2-34 Submitted at Oral Hearing March 18, 2014 - FortisBC Undertaking No. 14 re. Volume 6, Page 1269, Line 10 to Page 1271, Line 10

B2-35 Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 15,V6, p1210, SQI Incentive Payments

B2-36 Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 16, V4, p772 Scenarios

INTERVENOR DOCUMENTS

C1-1 **MINISTRY OF ENERGY AND MINES (MEM)** Online Registration and Letter dated July 18, 2013 – Request for Intervener Status by Katherine Muncaster

C2-1 **IRRIGATION RATEPAYERS GROUP (IRG)** Online Registration and Letter dated July 18, 2013 – Request for Intervener Status by Fred Weisberg

C2-2 Letter Dated November 27, 2013 –IRG Submitting Comment regarding FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2

C2-3 Letter Dated January 13, 2014 – IRG Submission on the Remainder of the Regulatory Timetable

C2-4 Letter Dated May 2, 2014 - IRG Comments regarding CEC Extension Request

C3-1 **BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCPSO)** Letter dated July 22, 2013 – Request for Intervener Status by Tannis Braithwaite, Eugene Kung, Bill Harper and Russ Bell

C3-2 Letter dated August 21, 2013 – BCPSO Submitting Information Request No. 1

C3-3 Letter dated August 28, 2013 – BCPSO Submitting Comments on on COPE 378's Late Supplemental Information Request

C3-4 Letter dated November 1, 2013 – BCPSO Submitting Information Request No. 2 Non-PBR

C3-5 Letter dated November 15, 2013 – BCPSO Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C3-6 Letter Dated November 27, 2013 – BCPSO Submitting Comment regarding FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2

C3-7 Letter Dated December 19, 2013 – BCPSO Submitting Evidence

C3-8 Letter Dated January 13, 2014 – BCPSO Submission on the Remainder of the Regulatory Timetable

C3-9 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to BCSEA

C3-10 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to CEC

C3-11 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to COPE

C3-12 Letter Dated January 29, 2014 – BCPSO Submitting Response to BCUC IR No. 1

C3-13 Letter Dated January 29, 2014 – BCPSO Submitting Response to FEI-FBC IR No. 1

C3-14 Letter Dated February 12, 2014 – BCPSO Submitting IR No. 2 to CEC on Intervener Evidence

C3-15 Letter Dated February 26, 2014 – BCPSO Submitting Response to BCUC IR No. 2

C3-16 Letter Dated February 26, 2014 – BCPSO Submitting Response to CEC IR No. 2

C3-16-1 Letter Submitted March 3, 2014 – BCPSO Filing Response to CEC IR No.2.2.3

C3-17 Letter Dated March 3, 2014 – BCPSO Submitting Comments regarding FEI-FBC Objection to CEC IR Responses

C3-18 Letter Dated March 3, 2014 – BCPSO Submitting Witness Panel

C3-19 Letter Dated April 30, 2014 - BCPSO Comments regarding CEC Extension Request

C4-1 **CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated July 22, 2013 – Request for Intervener Status by Jim Quail and Leigha Worth

C4-2 Letter dated August 21, 2013 – COPE 378 Submitting Information Request No. 1

C4-3 Letter dated August 23, 2013 – COPE 378 Submitting Information Regarding Consultant

C4-4 Letter dated August 22, 2013 – COPE 378 Submitting Late Supplementary Information Requests

C4-5 Letter dated August 28, 2013 – COPE 378 Submitting Comments and Corrected Supplemental Information Request to FBC

C4-6 Letter dated September 20, 2013 – COPE 378 Submitting Application to Amend Regulatory Timetable

C4-7 Letter dated November 13, 2013 – COPE 378 Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C4-8 Letter dated December 10, 2013 – COPE 378 Submitting Responses to FEI (B2-13)-FBC (B-29) Information Request

C4-9 Letter dated December 17, 2013 - COPE 378 Submitting Evidence

C4-10 Letter Dated January 14, 2014 – COPE 378 Late Submission on the Remainder of the Regulatory Timetable

C4-11 Letter Dated January 29, 2014 – COPE 378 Submitting Response to BCUC IR No. 1

C4-12 Letter Dated January 29, 2014 – COPE 378 Submitting Response to FEI-FBC IR No. 1

C4-13 Letter Dated January 29, 2014 – COPE 378 Submitting Response to BCSEA IR No. 1

C4-14 Letter Dated January 29, 2014 – COPE 378 Submitting Response to CEC IR No. 1

C4-14-1 Letter Dated January 30, 2014 – COPE 378 Submitting Updated Response to CEC IR No. 1

C4-15	Letter Dated February 5, 2014 – COPE 378 Submitting Late Responses to Information Requests
C4-16	Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to BCSEA IR No. 2
C4-17	Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to CEC IR No. 2
C4-18	Letter Dated February 28, 2014 – COPE 378 Submitting Comment on FEI-FBC-Objections to CEC IR Responses
C4-19	Letter Dated March 3, 2014 – COPE 378 Submitting Witness Panel
C4-20	Letter Dated April 29, 2014 - COPE 378 Comments regarding CEC Extension Request
C4-21	Letter Dated July 10, 2014 - COPE 378 Submitting Comments regarding Oral Argument Phase
C5-1	**BRITISH COLUMBIA MUNICIPAL ELECTRICAL UTILITIES (BCMEU)** Letter dated July 22, 2013 – Request for Intervener Status by Christopher Weafer
C5-2	Letter dated August 21, 2013 – BCMEU Submitting Information Request No. 1
C6-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** - Letter dated July 8, 2013 – Request for Intervener Status by Christopher Weafer
C6-2	Letter Dated August 21, 2013 – CEC Submitting Late Information Request No. 1
C6-3	Submitted at Hearing September 5, 2013 - Proposed Schedule
C6-4	Letter dated November 1, 2013 – CEC Submitting Information Request No. 2 Non-PBR
C6-5	Letter dated November 15, 2013 – CEC Submitting Information Request No. 2 on Performance Based Rates Methodology issues
C6-6	Letter dated November 18, 2013 – CEC Submitting Supplemental Information Requests
C6-7	Letter Dated November 27, 2013 – CEC Submitting Comment regarding FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2

C6-8	Letter dated December 16, 2013 - CEC Submitting Filing Extension Request
C6-9	Letter Dated December 20, 2013 – CEC Submitting Evidence
C6-9-1	Letter Dated January 7, 2014 — CEC Submitting Errata to Evidence
C6-10	Letter Dated January 13, 2014 – CEC Submission on the Remainder of the Regulatory Timetable
C6-11	Letter Dated January 16, 2014 – CEC Submitting Information Request No. 1 to COPE
C6-12	Letter Dated January 29, 2014 – CEC Submitting Response to BCUC IR No. 1
C6-12-1	Letter Dated January 30, 2014 – CEC Submitting Further Response to BCUC IR No. 1
C6-13	Letter Dated January 29, 2014 – CEC Submitting Response to BCSEA IR No. 1
C6-13-1	Letter Dated January 31, 2014 – CEC Submitting Further Response to BCSEA IR No. 1
C6-14	Letter Dated January 29, 2014 – CEC Submitting Response to BCPSO IR No. 1
C6-14-1	Letter Dated January 31, 2014 – CEC Submitting Further Response to BCPSO IR No. 1
C6-15	Letter Dated January 29, 2014 – CEC Submitting Response to FEI FBC IR No. 1
C6-15-1	Letter Dated February 5, 2014 – CEC Submitting Further Responses to FEI FBC IR No. 1
C6-16	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to BCSEA on Intervener Evidence
C6-17	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to BCPSO on Intervener Evidence
C6-18	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to COPE on Intervener Evidence
C6-19	Letter Dated February 26, 2014 – CEC Submitting Response to BCPSO IR No. 2
C6-20	Letter Dated February 26, 2014 – CEC Submitting Response to BCSEA IR No. 2
C6-20-1	Letter Dated March 4, 2014 – CEC Submitting Update to BCSEA IR No. 2.16.1
C6-21	Letter Dated February 26, 2014 – CEC Submitting Response to BCUC IR No. 2

C6-21-1 Letter Dated March 4, 2014 – CEC Submitting Update to BCUC IR No.2.12.1

C6-22 Letter Dated February 26, 2014 – CEC Submitting Response to FEI FBC IR No. 2

C6-23 Letter Dated March 3, 2014 – CEC Submitting Witness Panel

C6-24 Letter Dated March 3, 2014 – CEC Submitting Comments regarding FEI-FBC Objection to CEC IR Responses

C6-25 Letter Dated March 28, 2014 – CEC Information Request to FEI on Rebuttal Evidence

C6-26 Letter Dated April 29, 2014 - CEC Extension Request

C6-27 Letter Dated June 27, 2014 - CEC Responses to Panel Information Request No. 1

C6-28 Letter Dated July 10, 2014 - CEC Submitting Comments regarding Oral Argument Phase

C7-1 **GABANA, NORMAN (GABANA)** Letter dated July 22, 2013 – Request for Intervener Status by Norman Gabana

C7-2 Letter dated August 21, 2013 – Gabana Submitting Information Request No. 1

C7-3 Letter dated October 1 , 2013 – Gabana Submitting Comments regarding FBC IR No. 1 Responses

C7-4 Letter dated October 31 , 2013 – Gabana Submitting Response to BCUC

C7-5 Letter Dated May 5, 2014 - Gabana Late Comments regarding CEC Extension Request

C8-1 **BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB BRITISH COLUMBIA (BCSEA)** Letter dated July 23, 2013 – Request for Intervener Status by William Andrews and Thomas Hackney

C8-2 Letter dated July 23, 2013 – BCSEA Submitting Confidentiality Undertakings

C8-3 Letter dated August 21, 2013 – BCSEA Submitting Information Request No. 1

C8-3-1 Letter Dated August 22, 2013 – BCSEA Submitting Revised-black-lined Information Request No. 1

C8-4 Letter Dated August 27, 2013 – BCSEA Submitting Comment on COPE 378’s Late Supplemental Information Request

C8-5	Letter dated August 29, 2013 – BCSEA Submitting Consultants Confidentiality Undertakings
C8-6	Letter dated November 1, 2013 – BCSEA Submitting Information Request No. 2 Non-PBR
C8-7	Letter Dated November 27, 2013 –BCSEA Submitting Comment regarding FBC's Notice of Delay for filing responses to BCUC IR No. 2 and CEC IR No. 2
C8-8	Letter dated December 16, 2013 - BCSEA Submitting Filing Extension Request and Comments
C8-9	Letter Dated December 20, 2013 – BCSEA Submitting Evidence
C8-9-1	**CONFIDENTIAL** Letter Dated December 20, 2013 – Table 7
C8-10	Letter Dated January 13, 2014 – BCSEA Submission on the Remainder of the Regulatory Timetable
C8-11	Letter Dated January 16, 2014 – BCSEA Submitting Information Request No. 1 to ICG
C8-12	Letter Dated January 16, 2014 – BCSEA Submitting Information Request No. 1 to CEC
C8-13	Letter Dated January 16, 2014 – BCSEA Submitting Information Request No. 1 to COPE
C8-14	Letter Dated January 29, 2014 – BCSEA Submitting Response to BCUC IR No. 1
C8-15	Letter Dated January 29, 2014 – BCSEA Submitting Response to FEI-FBC IR No. 1
C8-15-1	**CONFIDENTIAL** Letter Dated January 29, 2014 – BCSEA Submitting Confidential Response to FEI-FBC IR No. 1
C8-16	Letter Dated January 29, 2014 – BCSEA Submitting Response to BCPSO IR No. 1
C8-17	Letter Dated February 12, 2014 – BCSEA Submitting IR No. 2 to CEC on Intervener Evidence
C8-18	Letter Dated February 12, 2014 – BCSEA Submitting IR No. 2 to COPE on Intervener Evidence
C8-19	Letter Dated February 26, 2014 – BCSEA Submitting Response to CEC IR No. 2
C8-20	Letter Dated February 28, 2014 – BCSEA Submitting Comment on FEI-FBC-Objections to CEC IR Responses

C8-21 Letter Dated February 28, 2014 – BCSEA Submitting Notice

C8-22 Letter Submitted March 10, 2014 – BCSEA Submitting Opening Statement Presentation

C8-23 Letter Dated March 28, 2014 – BCSEA Information Request No. 1 to FBC on Rebuttal Evidence

C8-24 Letter Dated March 28, 2014 – BCSEA Information Request No. 1 to BCUC

C8-25 Letter Dated May 1, 2014 - BCSEA Comments regarding CEC Extension Request

C9-1 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration Dated July 23, 2013 – Request for Intervener Status by Janet Fraser

C10-1 **INDUSTRIAL CUSTOMERS GROUP (ICG)** Letter dated July 24, 2013 – Request for Intervener Status by Brian Merwin, Robert Hobbs and Elroy Switlishoff

C10-2 Letter Dated August 21, 2013 – ICG Submitting Information Request No. 1

C10-3 Letter dated November 1, 2013 – ICG Submitting Information Request No. 2 Non-PBR

C10-4 Letter dated November 15, 2013 – ICG Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C10-5 Letter Dated December 20, 2013 – ICG Submitting Evidence

C10-6 Letter Dated January 13, 2014 – ICG Submission on the Remainder of the Regulatory Timetable

C10-7 Letter Dated January 30, 2014 – ICG Submitting Late Response to BCUC IR No. 1

C10-8 Letter Dated January 30, 2014 – ICG Submitting Late Response to BCSEA IR No. 1

C10-9 Letter Dated February 26, 2014 – ICG Submitting Response to BCUC IR No. 2 (Received February 25, 2014)

C10-10 Letter Dated May 1, 2014 - ICG Comments regarding CEC Extension Request

C11-1 **STANSKI, HENRY (STANSKI)** Letter Dated July 24, 2013 – Request for Intervener Status by Henry Stanski

C11-2 Letter Dated August 22, 2013 – Stanski Submitting late Information Request No. 1

C12-1 Submitted at Oral Hearing March 11, 2014 – COPE Letter From Jim Quail With Attached Evidence of Barbara R. Alexander Dated December 18, 2013

C12-2 Submitted at Oral Hearing March 11, 2014 – CEC Opening Comments-2014 Through 2018

C12-3 Submitted at Oral Hearing March 12, 2014 – COPE Opening Statement of Barbara R. Alexander on Behalf of COPE Local 378

C12-4 Submitted at Oral Hearing March 12, 2014 – CEC Opening Comments on B&V's Rebuttal Testimony, Mark Lowry Dated 12 March 2014

C12-5 Submitted at Oral Hearing March 14, 2014 – COPE 378 Extracted Reference Exhibits For Cross-Examination Of FortisBC Witness Panel No. 2

C12-6 Submitted at Oral Hearing March 17, 2014 - Extracts From FortisBC Electric Final Argument in the 2012-2013 RRA and ISP Proceeding

C12-7 Submitted at Oral Hearing March 17, 2014 - One-Page Petition with 16 Signatures

C12-8 Submitted March 19, 2014 – COPE Undertaking-Hearing Date March 14, 2014 Volume 5, Page 1010, Line 7 to 12

INTERESTED PARTY DOCUMENTS

D-1 **IBEW LOCAL 213 MEMBERS (IBEW)** Online Registration and Letter Dated July 24, 2013 – Request for Interested Party Status by Rod Russell

D-2 **ALLAN, BEVERLY (ALLAN)** Letter Dated July 24, 2013 – Request for Interested Party Status by Beverly Allan

LETTERS OF COMMENT

E-1 Johnson, Colby - Letter of Comment dated July 10, 2013

E-2 Fenton,R and Haidenger, T Letter of Comment dated September 9, 2013– Redacted version on web only

E-3 Cancelliere, Ryan Letter of Comment dated September 12, 2013– Redacted version on web only

E-4	Farness, Rod Letter of Comment dated September 11, 2013– Redacted version on web only
E-5	Russell, Rod Letter of Comment dated September 13, 2013– Redacted version on web only
E-6	Hiebert, Kerry Letter of Comment dated September 14, 2013– Redacted version on web only
E-7	Kingsfield, Laurie Letter of Comment dated September 13, 2013– Redacted version on web only – Redacted version on web only
E-8	Dergousoff, Scott Letter of Comment dated September 13, 2013– Redacted version on web only
E-9	Traynor, Sharon Letter of Comment dated September 15, 2013– Redacted version on web only
E-10	Deyotte, Sharon Letter of Comment dated September 16, 2013– Redacted version on web only
E-11	Foyle, Carol Ann Letter of Comment dated September 17, 2013– Redacted version on web only
E-12	Verigin, Wally Letter of Comment dated September 17, 2013
E-13	Wayling, Kirby Letter of Comment dated September 17, 2013– Redacted version on web only
E-14	Cancelliere, Darryl Letter of Comment dated September 19, 2013– Redacted version on web only
E-15	Trubetskoff, T Letter of Comment dated September 18, 2013– Redacted version on web only
E-16	Chatten, Chuck and JoAnn Letter of Comment dated September 22, 2013– Redacted version on web only
E-17	Kokiw, D Letter of Comment dated September 22, 2013– Redacted version on web only
E-18	MacMurrary, T Letter of Comment dated September 21, 2013– Redacted version on web only

E-19	Ross, S Letter of Comment dated September 23, 2013– Redacted version on web only
E-20	Smith, C Letter of Comment dated September 23, 2013– Redacted version on web only
E-21	Verigin, L Letter of Comment dated September 22, 2013– Redacted version on web only
E-22	Desnoyers, B and R Letter of Comment dated September 26, 2013– Redacted version on web only
E-23	Adamson, J Letter of Comment dated September 27, 2013– Redacted version on web only
E-24	Miner, D Letter of Comment dated September 28, 2013 – Redacted version on web only
E-25	Kutzner, Walter Letter of Comment received October 1, 2013 2013 – Redacted version on web only
E-26	Macklon, Chuck Letter of Comment received October 4, 2013 2013 – Redacted version on web only
E-26-1	Macklon, Chuck Letter of Comment received October 9, 2013 2013 – Redacted version on web only
E-27	MacLeod, Cherryl Letter of Comment received October 5, 2013 2013 – Redacted version on web only
E-28	Mock, David Letter of Comment received October 8, 2013 2013
E-29	Bortolussi, Brenda Letter of Comment received October 11, 2013 2013 – Redacted version on web only
E-30	Peebles, Clinton Letter of Comment received October 11, 2013 2013 – Redacted version on web only
E-31	Munn, Roger Letter of Comment dated October 15, 2013 2013 – Redacted version on web only
E-32	Thomas, Neil Letter of Comment dated October 13, 2013 2013 – Redacted version on web only

E-33 Thomas, Sarah Letter of Comment dated October 11, 2013 2013 – Redacted version on web only

E-34 Dunnett, Rod Letter of Comment dated October 16, 2013 2013 – Redacted version on web only

E-35 Keightley, J Letter of Comment dated October 15, 2013 2013 – Redacted version on web only

E-36 Marley, Dawn Letter of Comment dated October 17, 2013 2013 – Redacted version on web only

E-37 Warrior, Mark Letter of Comment dated October 17, 2013 2013 – Redacted version on web only

E-38 Zirk, Tammy Letter of Comment dated October 17, 2013 – Redacted version on web only

E-39 Chambers, Justin Letter of Comment dated October 18, 2013 - Redacted version on web only

E-40 Coombs, Tom Letter of Comment dated October 18, 2013 – Redacted version on web only

E-41 Desnoyers, Brenda Letter of Comment dated October 18, 2013 – Redacted version on web only

E-42 Duke, Donna Letter of Comment dated October 17, 2013 – Redacted version on web only

E-43 Heather Letter of Comment dated October 18, 2013 – Redacted version on web only

E-44 Booth, Bronwyn Letter of Comment dated October 18, 2013 - Redacted version on web only

E-45 Dinner, Bill Letter of Comment dated October 18, 2013 - Redacted version on web only

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E-47 Tokarchuk, Maria Letter of Comment dated October 19, 2013 - Redacted version on web only

E-48 Voigt, Darlene Letter of Comment dated October 21, 2013 - Redacted version on web only

E-49 Hamilton, Nicky Letter of Comment dated October 18, 2013 - Redacted version on web only

E-50 Duclos, Christy Letter of Comment dated October 21, 2013 - Redacted version on web only

E-51 Cresswell, Lila Letter of Comment dated October 22, 2013 - Redacted version on web only

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E-53 Smith, Alisha Letter of Comment dated October 23, 2013 - Redacted version on web only

E-54 Voigt, Shane Letter of Comment dated October 22, 2013 - Redacted version on web only

E-55 Critchley, D Letter of Comment dated October 21, 2013 - Redacted version on web only

E-56 Barkley, L Letter of Comment dated November 1, 2013 - Redacted version on web only

E-57 Dawkins, L Letter of Comment dated October 22, 2013 - Redacted version on web only

E-58 DeCosse, R Letter of Comment dated October 25, 2013 - Redacted version on web only

E-59 Macklon, C Letter of Comment dated October 24, 2013 - Redacted version on web only

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E-61	Mayer, T Letter of Comment dated November 1, 2013 - Redacted version on web only
E-62	Milne, D Letter of Comment dated October 22, 2013 - Redacted version on web only
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E-65	Clemence, B Letter of Comment dated November 7, 2013 - Redacted version on web only
E-66	PENDING Robin Letter of Comment dated November 4, 2013
E-67	Fillmore, L Letter of Comment dated November 17, 2013 - Redacted version on web only
E-68	Kutzner, W Letter of Comment dated November 18, 2013
E-69	Whitbread, SJ and JP Letter of Comment dated November 13, 2013 - Redacted version on web only
E-70	Belanger, R Letter of Comment dated November 22, 2013 - Redacted version on web only
E-71	Penny, J Letter of Comment dated November 22, 2013 - Redacted version on web only
E-72	Bedin, D Letter of Comment dated November 29, 2013 - Redacted version on web only
E-73	Lower Columbia Community Development Team Society Letter of Comment dated December 19, 2013 - Redacted version on web only
E-74	Clyde, D Letter of Comment dated January 22, 2014 – Redacted version on web only
E-75	Stuart, B Letter of Comment dated March 14, 2014 – Redacted version on web only

E-76	Speckeen, F Letter of Comment dated March 15, 2014 – Redacted version on web only
E-76-1	Speckeen, F Letter of Comment 2 dated March 18, 2014 – Redacted version on web only
E-77	Sommerey, R Letter of Comment dated March 14, 2014 – Redacted version on web only
E-77-1	Sommerey, R Letter of Comment dated March 21, 2014 – Redacted version on web only
E-78	Dawson, P Letter of Comment dated April 4, 2014 – Redacted version on web only
E-79	Opper, C & L Letter of Comment dated April 9, 2014 – Redacted version on web only
E-80	MacNeil, M Letter of Comment dated April 15, 2014 – Redacted version on web only
E-81	Diduch Letter of Comment dated April 24, 2014 – Redacted version on web only

IN THE MATTER OF

FortisBC Energy Inc.

Multi-Year Performance Based Ratemaking Plan For 2014 Through 2018

Decision

September 15, 2014

Before:

D.M. Morton, Panel Chair/Commissioner
D. A. Cote, Commissioner
N. E. MacMurchy, Commissioner

LIST OF TABLES

EXECUTIVE SUMMARY

On June 12, 2013, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014–2018 (Application). The Application was made pursuant to sections 59-61 and 44.2 of the *Utilities Commission Act* (UCA). FEI, among other things, seeks approval of requests in the following areas:

- PBR mechanisms and the rate stabilization mechanism for setting rates for the years 2014–2018.
- Permanent rates for all customers effective January 1, 2014 resulting in an increase of 0.6 percent over 2013 and the flow through of any rate increase or decrease resulting from the Generic Cost of Capital (Stage 2) proceeding.
- Deferral accounts additions, changes and discontinuance as well as proposed changes in financing costs.
- Accounting policies including the allocation of executive costs, the capitalized overhead rate and direct overhead charging methodology.
- Demand Side-Management (DSM) related to 2014-2018 expenditures and amortization changes.

FEI has filed this 2014-2018 PBR plan based on the following objectives:

1. To reinforce FEI's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

On July 5, 2013, FortisBC Inc. (FBC) filed a similar application. Portions of each application concerned with the PBR mechanism were combined into a joint proceeding. For convenience the joint applicants in that portion of the proceeding are referred to as Fortis.

Many of the interveners expressed concern with the Fortis proposal and recommended denying the Application in favour of moving forward with additional process to resolve the issues that arose. Considering the time and money spent to conduct the proceeding and the considerable volume of evidence, the Commission Panel determines it is appropriate to move forward with the process and render a decision based on the substantial evidentiary record. The Panel considers much of the problem among the parties is based on a lack of trust which, over time, must be addressed if a PBR regimen is to be successful.

The Decision following the Introduction section has been separated into three sections:

- PBR Design which deals with determinations related to the PBR formula components and elements of the PBR plan including the management of Service Quality Indicators (SQI);
- Making the PBR Work which addresses key revenue requirement issues including Base Operations and Maintenance (O&M) and Base Capital, accounting policy proposals and a number of issues with deferral accounts; and
- Demand-Side Management (DSM) Programs.

PBR Design

A brief summary of some of the key issues and determinations related to the PBR design components are as follows:

PBR Formula Components

(a) **PBR Term:** Fortis' proposal is for a five year PBR term starting in 2014. Most interveners favoured a shorter term pointing to the risk associated with a five year term. The Commission Panel in recognition of the timing of this Decision, determines that a six year period ending in 2019 is optimum. In the Panel's view, the changes made to certain PBR mechanisms provide the necessary checks and balances to protect ratepayer interests.

(b) **I-Factor:** The Commission Panel supports the use of BC-CPI and the BC-AWE indexes in the determination of the I-factor as recommended by Fortis. However, the Panel is not persuaded that relying on forecast data to determine the I-factor is appropriate. We find that a reliance on the previous year's actual index figures, while backward looking, has significant advantages and therefore have determined this method to be most appropriate.

(c) **X-Factor:** Considering the opposing views of two expert witnesses, Dr. Overcast on behalf of Black and Veatch (B&V) and Dr. Lowry on behalf of Pacific Economic Group (PEG), the Panel does not accept the B&V study results due to methodology shortcomings and resulting errors but places considerable weight on the PEG study considering it more rigorous. The Commission Panel determines an X-factor of 1.1 is appropriate for FEI.

PBR Plan Components

(a) **Earnings Sharing Mechanism:** The Commission Panel determines that an Earnings Sharing Mechanism where gains and losses are shared equally by the Company and the ratepayer balances the interests of the customer and the utility.

(b) **Efficiency Carry-over Mechanism:** Fortis proposes an efficiency carry-over mechanism (ECM) to allow the utility to benefit from savings following the PBR period resulting from measures taken and costs incurred during PBR. The interveners opposed this proposal considering it one sided and favouring the utility. The Commission Panel denies the Fortis ECM request but remains open to its inclusion where warranted.

(c) **Service Quality:** Considering the evidence, the Commission Panel determines there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. It further determines a list of SQIs and sets performance benchmarks for each. The Panel acknowledges the need for an acceptable performance range for each SQI and directs the Fortis Companies in consultation with the stakeholders to develop these ranges.

(d) **Capital Expenditures:** Fortis has proposed an approach to capital which excludes Certificate of Public Convenience and Necessity (CPCN) related capital from the PBR plan. Interveners have raised concerns with respect to inclusion of capital pointing out various shortcomings. The Commission Panel finds the Fortis proposed CPCN criteria to be inappropriate for determining what capital is excluded from the PBR formula and favours establishment of a dollar threshold. On a temporary basis, the Panel approves the current CPCN exclusion criteria and sets a process to further examine issues related to dollar thresholds and management of capital within the PBR.

(e) **Mid-Term and Annual Review Process:** The Commission Panel finds that an extensive Annual Review process is necessary to build trust among the stakeholders and ensure the PBR plan functions as intended. The Panel sets out a list of items which it directs the parties to address within the Annual Review. Given this more comprehensive approach to Annual Reviews, there is no need for the proposed Mid-Term Review and it is therefore denied.

Making the PBR Work

A brief summary of some of the key issues and determinations related to FEI's Non PBR components are as follows:

<u>Determining Base Operating and Maintenance (O&M) and Capital</u>

(a) **Base O&M:** The methodology for determining Base O&M proposed by FEI is to use the 2013 Approved O&M as a starting point and make adjustments to arrive at the PBR Opening Base O&M figure. Interveners expressed concern with both the methodology and the proposed adjustments. The Commission Panel determines that 2013 Approved O&M is an appropriate starting point and determines that further adjustments to the PBR Opening O&M Base are required resulting in a minor overall reduction to FEI's proposed base.

(b) **Base Capital:** Given that there is to be a more fulsome review of issues related to dollar thresholds and the management of capital within the PBR, the Commission Panel approves FEI's approach to formula capital and approves FEI's Base Capital as applied for, subject to further adjustment as directed elsewhere in this Decision.

Accounting Policies

The Commission Panel approves a number of proposed accounting changes including the discontinuance of the US Generally Accepted Accounting Principles (GAAP) to Canadian GAAP reconciliation, changes to the handling of Pension and Other Post-Employment Benefits (OPEB) funding differences and application of the Massachusetts Formula for executive costs. The Panel directs FEI to reduce its capitalized overhead rate to 12 percent in 2014 as well as to commence expensing its annual software upgrade costs consistent with the direction provided to FEI in its 2012–2013 RRA Decision.

Deferral Accounts

(a) **2012–2014 Application Costs Deferral Account:** The Commission Panel approves FEI's proposal to establish the 2012–2014 Application costs Deferral Account and also approves the amortization of its balance over the six year PBR period.

(b) **Thermal Energy Services Deferral Account (TESDA) Overhead Allocation Variance Deferral Account:** The Commission Panel approves the TESDA Overhead Allocation Variance Deferral Account and directs that the December 31 balance each year be amortized into rates the following year.

FEI is directed to discontinue the use of the Tax Variance, Property Tax Variance, Insurance Expense Variance and Interest Expense Variance Deferral Accounts. Although the Panel approves the flow through treatment of these expenses, FEI is directed to flow through variances between forecast and actual expenses in these accounts through the annual true up mechanism.

The Panel approves FEI's amortization requests, with the exception of the following, where the Panel directs:

1. The reduction of the amortization period from 3 to 2 years for the Southern Crossing Pipeline (SCP) Mitigation Revenues Variance Account.

2. Continuance of the amortization period of the Pension and OPEB Variance deferral account at three years.

The Panel denies FEI's request to capture 2012 Biomethane application related costs in the existing Biomethane Program Costs deferral account. Instead it is directed to record these costs in the Biomethane Variance account.

Other FEI requests concerning creation, amortization and discontinuance of deferral accounts as proposed by FEI are approved.

Demand-Side Management

The Commission accepts FEU's proposed DSM expenditure schedule as follows:

	(thousands)
2014	$34,353
2015	$36,537
2016	$35,839
2017	$35,388
2018	$35,874

including approval for new EEC program initiatives. However, the Panel directs FEU to submit a detailed plan for each new program for approval prior to the expenditure of any funds. The Panel also directs FEU to file, by the end of 2015, one or more EEC programs intended to specifically address the unique barriers to energy efficiency faced by renters.

The Commission Panel approves FEU's request to (i) continue the EEC accounting treatment approved for 2012–2013 and (ii) to transfer any new amounts accumulated in the non-rate base EEC deferral account to FEU rate base EEC deferral account in the following year. The Commission Panel directs FEU to include in the next FEU EEC Application an analysis of the rate impact of a reduction in the EEC amortization period to eight years and to five years.

The Commission Panel approves the third-party administration portion of the PWC proposal put forward by FEU. However, the Panel does not approve the initial and subsequent annual backward-looking review portion of the PWC proposal. The Commission Panel denies FEU's request to place the actual expenditures from PWC's administration of EEC funds for projects with a thermal energy component in the EEC non-rate base deferral account that attracts AFUDC.

1.0 INTRODUCTION

1.1 Background

FortisBC Energy Inc. (FEI) distributes natural gas to approximately 835,000 customers mainly in the Lower Mainland and Interior regions of British Columbia.

On February 26, 2014, Commission Order G-21-14 approved the amalgamation of FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI), FortisBC Energy (Whistler) Inc. (FEW) (together the FortisBC Energy Utilities, or FEU) and Terasen Gas Holdings Inc., effective January 1, 2015.

On June 10, 2013, FEI submitted an application seeking British Columbia Utilities Commission (Commission) approval of a multi-year performance based ratemaking (PBR) plan for the years 2014 through 2018 (PBR Plan), including approval of rates for 2014 in accordance with the PBR Plan (Application).

In its Application, FEI cites the following primary objectives of the PBR Plan:

- To reinforce FEI's productivity improvement culture while ensuring safety and customer service requirements continue to be met; and
- To create an efficient regulatory process for the upcoming years allowing the Company to focus on effectively managing business priorities and minimizing costs for customers.

FEI has had one previous PBR plan (2004–2009). From 2010 to 2013 FEI was regulated under the Cost of Service (COS) rate setting mechanism.

1.2 The Application and Approvals Sought

FEI seeks certain approvals under sections 59-61 of the *Utilities Commission Act* (UCA) in order to implement the PBR Plan. The approvals sought are broken down into several areas and are described below.

1.2.1 PBR Plan

FEI seeks:

- Approval of the PBR mechanisms set out in Section B of the Application for setting rates for the years 2014–2018.

1.2.2 General Rate Increases

FEI also seeks:

- A delivery rate increase of 0.6 percent for all non-bypass customers effective January 1, 2014, with the increase to be applied to the delivery charge, holding the basic charge at 2013 levels; and (Exhibit B-1-5, Attachment 4, p. 6)
- Approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23 effective January 1, 2014 of a credit amount of $0.120/GJ as set out in Section E Schedule 63 of the Application. (Exhibit B-15).

1.2.3 Accounting Policies Changes, Effective January 1, 2014

FEI seeks approval for the following:

- Changes to the following accounting policies to be used in the determination of rates for FEI effective January 1, 2014:
  a. Modification to the approved Lead Lag days with the removal of the HST lead days and the insertion of GST and PST lead days as set out in Section D3.2 of the Application;
  b. Inclusion of the retiree portion of pension and Other Post-Employment Benefits (OPEB) expenses in benefit loadings for Operating and Maintenance (O&M) and capital as set out in Section D3.1 of the Application;
  c. Capitalization of the annual software costs paid to vendors in support of upgrade capability as set out in Section D3.1 of the Application;
  d. Depreciation to commence January 1 of the year following when the asset is placed into service as set out in Section D3.3 of the Application;

e. A depreciation rate of 12.5 percent for asset class 484 Vehicles as set out in Section D3.1 of the Application;

f. Approval to discontinue the reconciliation of US Generally Accepted Accounting Principles (GAAP) to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application; and

g. Approval to allocate Executive costs between FEI and FortisBC Inc. (FBC) effective January 1, 2014 by way of applying the Massachusetts Formula as described in Section D3.6.5 of the Application.

- The continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2014–2018 PBR Period as set out in Section C2.3 of the Application; and
- The allocation of costs for corporate services between FortisBC Holdings Inc. (FHI) and FEI and for Shared Services as between FEI and FEVI, and between FEI and FEW, as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Section D3.6 of the Application.

1.2.4 Deferral Accounts

FEI seeks approval of the following:

- Discontinuance, modification and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI as set out in Section D4 and Appendices F4 and F5 of the Application.

1.2.5 Energy Efficiency and Conservation (EEC) Expenditures

FEI seeks:

- Acceptance pursuant to section 44.2(3) of the UCA of the following EEC expenditure schedules for FEU to be spent on the EEC program areas described in Appendix I of the Application: Up to $34.353 million for 2014 (inclusive of the $15 million accepted by Order G-230-13), $37.303 million for 2015, $37.358 million for 2016, $37.664 million for 2017 and $38.982 million for 2018.

- Continuation of the EEC framework approved by the Commission, with the following changes:
    a. Approval of the administration by a neutral third party of EEC funds provided to projects with a third party thermal energy component;
    b. Approval of the incorporation of spillover effects and the attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, for the purpose of reporting on cost effectiveness in the EEC Annual Report pursuant to section 43 of the UCA; and
    c. Approval for FEU to transfer funds within a program area to a new program without prior Commission approval, provided that the new program is in accordance with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

1.3 Regulatory Framework

FEI seeks approval of its PBR Plan, including appropriate rate increases, pursuant to sections 59 to 61 of the UCA. In summary, these sections of the UCA require the Commission to have due regard for setting rates that are not unjust or unreasonable in respect of services provided by the applicant. Subsection 59 (5) states that a rate is 'unjust' or 'unreasonable' if it is:

a. more than a fair and reasonable charge for service of the nature and quality provided by the utility,

b. insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

c. Unjust and unreasonable for any other reason.

<u>EEC Expenditures</u>

FEI also seeks approval of proposed EEC capital expenditures for the duration of the PBR Plan pursuant to subsection 44.2 (3) of the UCA. The regulatory framework applicable to the evaluation of the proposed EEC expenditures is laid out in Section 4 of this Decision.

1.4 Regulatory Process

FEI filed its Application on June 10, 2013. By Order G-99-13, dated June 21, 2013, a Preliminary Regulatory Timetable and Procedural Conference were established.
There were six Registered Interveners although not all fully participated in the regulatory hearing process. The Registered Interveners were:

- British Columbia Pensioners' and Seniors' Organization (BCPSO);
- Canadian Office and Professional Employees Union Local 378 (COPE);
- Commercial Energy consumers of British Columbia (CEC);
- BC Sustainable energy Association and the Sierra Club of British Columbia (BCSEA);
- Coalition for Open Competition (COC);
- British Columbia Hydro and Power Authority (BC Hydro).

There were four expert witnesses who provided evidence and actively participated in the regulatory process. Expert Witnesses and their respective parties were as follows:

- Dr. H. Edwin Overcast on behalf of Black & Veatch (Fortis);
- Ms. Barbara R. Alexander (COPE);
- Mr. Russ Bell (BCPSO); and
- Dr. Mark Lowry on behalf of Pacific Economic Group (CEC).

On July 5, 2013, FortisBC Inc. (FBC) filed an application also seeking to implement a PBR Plan of five years duration (2014–2018).

1.5 Approach to this Application

This Decision is separated into 4 Sections.

Section 1 provides background as well as an outline of the legislative framework and regulatory process for this proceeding. This Section will continue with a discussion of some of the issues which have arisen within the context of the proceeding which provides some guidance to the determinations which follow.

Section 2 considers the PBR Methodology. This includes a discussion and determinations on key design issues such as the PBR Formula components, the PBR Plan components and the management of Service Quality.

Section 3 covers how the PBR will work. It includes key issues like setting the Base for O&M and Capital, Accounting Policy Issues and the Use of Deferral Accounts.

Finally, Section 4 considers issues related to Demand-Side Management.

1.6 Issues Arising

Three contextual issues arose in this Proceeding that need to be addressed and serve to provide guidance to determinations made in this Decision. These issues are:

- Why Performance Based Regulation;
- A Fair Rate of Return Under PBR;
- Amalgamation of the FEU.

1.6.1 Why Performance Based Regulation

The fact that FEI has filed an Application for PBR is not a surprise to the Commission given that FEI has operated under PBR in the past and has been open about its intentions. What is surprising is the position taken by interveners with respect to PBR. After what appeared to be support for a PBR, a number of interveners are calling for a rejection of the PBR Plan as proposed by FortisBC Energy Inc. and FortisBC Inc. (Fortis) and recommend moving forward with further process to resolve the matter. The issue the Commission Panel must consider is whether the objections to PBR relate to performance based ratemaking itself or whether the concerns raised are founded on a desire to circumvent the established process and embark on an undefined process more to the Interveners' liking. In considering this issue, the Panel is mindful that an alternative negotiated settlement process was considered in the Reasons for Decision attached to Order G-150-13 issued on September 12, 2013. In these Reasons, the Panel stated "[f]or the PBR mechanism review, the Panel finds that that the oral hearing which provides an opportunity to cross examine expert witnesses is the most appropriate means to obtain a complete evidentiary record necessary to assess these complex and challenging methodologies" (Exhibit A-13, Reasons for Decision, p. 4). Having completed the regulatory process which included an oral hearing, the Panel will consider the fullness of the evidence in reaching its determination as to whether a PBR is appropriate and whether there is a need for additional process.

1.6.1.1 A Case for PBR

After four years of cost of service (COS) regulation, FEI has opted to file a multi-year PBR. FEI has filed this 2014–2018 PBR Plan based on the following primary objectives:

1. To reinforce FBC's productivity improvement culture, while ensuring safety and customer service requirements continue to be met; and
2. To create an efficient regulatory process for the upcoming years, allowing the Company to focus on effectively managing business priorities and minimizing cost for customers.

FEI states that its proposed PBR Plan builds on the successful components of its most recent PBR Plan, which ran from 2004 through 2009. The current Plan, like the earlier PBR, establishes a formula driven approach to calculating an incentive for management of O&M costs and for capital expenditures. Fortis considers these to be areas where it has the greatest control. FEI asserts that the proposed formula will result in lower spending targets in both of these areas when compared to the five year O&M and capital forecast prepared by the Company. This is because it is incented to invest in new efficiencies to meet targets driven by the formula. In those years where the Company achieves efficiencies greater than those driven by the formula, the financial benefits are shared with customers as are any shortfalls. The proposed PBR Plan utilizes flow-through accounts and annual forecasts to ensure that customers pay only the actual cost in those areas where FEI has limited or no control thereby protecting customers and the Company from the impact of forecast variances. The PBR Plan also includes off-ramp mechanisms to deal with cases where financial results fall outside a band of reasonableness or where there is serious, sustained and unjustified service quality degradation.

Black and Veatch (B&V) provides a study of PBR methodologies and concludes there is no one right PBR model and the adopted FEI framework should be in keeping with the Company's circumstances. FEI's position is that the proposed PBR Plan, as a model, will encourage it to seek efficiencies over the term of the plan with both customers and the Company benefiting while ensuring that safe and reliable service is maintained. B&V endorses the plan as being reasonable in the circumstances but believes the "stretch" productivity factor proposed by Fortis is more aggressive than is warranted. (Exhibit B-1, pp. 1–3)

FEI states that a priority is to improve productivity and create efficiencies to allow for rates to be more effectively managed, yet maintain a customer service focus. To this end, during 2012 and 2013 "[e]mployees were challenged to consider embedded practices and rethink work while maintaining appropriate service." (Exhibit B-1, pp. 11–13) FEI reports that this has resulted in efficiencies being realized from streamlined processes, leveraging technology and the optimization of integration opportunities with FBC. FEI states that efficiency review activities and finding productivity gains will continue to be a focus with an emphasis on managing costs. FBC further states:

> "In providing value for our customers while delivering safe and reliable service at the most reasonable cost, a productivity focus is a requirement and is ingrained into the Company. The implementation of the PBR Plan proposed in this Application will result in a continuation of this focus through the PBR Period, and in an equal sharing with customers of the resulting incremental savings above the productivity factor built into customer rates." (Exhibit B-1, pp. 11–13)

Intervener Submissions

In concluding its Opening Statement in the Oral Hearing, CEC states: "CEC is in support of PBR. This is not an issue. It simply does not see this proposal of the company at this time as aligned with customer interests and we will deal with how that may be improved in our final submissions and through this proceeding" (T2:188). CEC, in its Final Argument "recommends that the Commission deny the Utilities application for their proposed PBR process and direct the parties to commence discussion with respect to alternatives that may more suitably align customer interest and the Utilities interest." A summary of CEC's position includes the following concerns:

- The PBR formulas proposed by Fortis are overly generous and are likely to result in the utilities enjoying windfall gains.
- The PBR has incentives which could lead to losses or inappropriate gains for the customer. The build-up of expenses before entering PBR and the deferral of expenditures late in a PBR period serve as examples of such perverse incentives.
- The Fortis proposal includes numerous examples of misalignment with customer interests and has not assessed alternatives due to its failure to consult with customer groups. CEC continues by noting 178 examples of misalignment of ratepayer interest to shareholder interest it has identified and therefore approval of such a PBR proposal does not balance interests.
- Fortis has not made a sufficient business case for regulatory efficiency.

(CEC PBR Methodology Final Argument, p. 7)

CEC continues its submissions for a total of 219 pages outlining its concerns and sharing its view as to how the various PBR components can be better aligned with customer interests.

Industrial Consumers Group (ICG) reaches a similar conclusion with respect to FBC in that the PBR proposal is not aligned with customer interests and substantial changes are necessary. However, even with these changes, ICG does not support a PBR Plan at this time. (ICG Final Argument, p. 1)

Irrigation Ratepayers Group (IRG) acknowledges the economic basis for PBR generally but asserts that FBC has not adequately explained why a change to PBR is required. IRG asserts that FBC has not established that a PBR will result in material expansion of incremental efficiency savings or that regulatory efficiency will result if PBR is implemented. (IRG Final Argument, pp. 1, 10)

COPE in its Final Argument provided comments on some of the strengths and weaknesses of PBRs but took no position on the Application as a whole. COPE did provide detailed submissions on SQIs.

BCPSO took no position on whether to deny the Application but outlined alternative positions to those of Fortis with respect to customer alignment and balance in its Final Argument.

BCMEU, an intervener in the FBC Proceeding, in its Final Argument supports the arguments of CEC and the need for a PBR with a good balance of risk and reward.

The matter of whether to go forward with a PBR was addressed again within the context of the Oral Argument phase of the proceeding held on July, 14, 2014. The Interveners were consistent in their opposition of the PBR as proposed by Fortis. However, CEC did submit that an “improved and ongoing PBR could serve to mitigate customer concerns” (T8:1415). It continued by recommending that a BCUC supervised process be initiated immediately to develop a PBR process more aligned with customer interests.

Fortis Reply

In the view of Fortis, interveners like CEC, BCPSO and ICG pay lip service to the concept of a PBR while objecting to its fundamental elements. Fortis holds that the case in favour of PBR is compelling. It states that interveners representing customers consider COS to be the gold standard pointing to the detailed review of costs and typical rebasing every two years as the reason. This is in comparison to PBR where there are less detailed reviews of utility costs over the PBR period and a longer period (in this case five years) between rebasing. In Fortis’ view, the reason why PBR remains an accepted ratemaking model is that these two features are fundamental to the values of productivity and efficiency that the PBR delivers to utility customers. Fortis argues that:

- Extending the time before rebasing incents the utility to search for incremental efficiencies.
- The more streamlined regulatory process related to PBR increases the likelihood of achieving direct and indirect savings.
- An appropriate level of transparency can be achieved with a less intensive regulatory process in PBR.

Fortis considers much of the concern raised by interveners to be misconceptions. Some examples of these follow.

Fortis argues that some of the interveners consider PBR to be misaligned with customer interests by providing windfalls to the utility and harming customers by creating inappropriate incentives. It considers these views to be misconceived and to lack recognition of short- and long-term customer benefits as commented on by both CEC's expert witness, Dr. Lowry, and Fortis' expert witness, Dr. Overcast. Fortis further states that the achievement of a higher than approved ROE is a benefit because this only occurs when benefits have flowed to both parties. By comparison, under COS, 100 percent of the benefit flows to the Company and the customer obtains benefits only after rebasing.

In response to concerns raised by interveners that the Fortis PBR Plan does not distinguish between "efficiency gains" and "cost cutting", Fortis further states that cost cutting is efficient and beneficial. Fortis argues that the distinction is artificial as by definition efficiency occurs when the earned return equals or exceeds the allowed return under revenue cap when a positive stretch factor exists. In addition, Fortis states that the opposition of interveners to mere cost cutting seems to be based on a misconception that under-expenditures are a product of gamesmanship related to perverse incentives and are made at the expense of service quality and asset integrity. The Company points out that these types of arguments ignore the presumption of good faith and the existence of a regulator.

Fortis asserts that PBR will bring regulatory efficiency, pointing out that revenue requirements applications are 10 to 30 times more costly than the Annual Review Process under PBR. In addition, it is intuitive that there is a direct benefit related to having utility employees focus on managing the business rather than the regulatory process. (Fortis PBR Final Argument, pp. 1–16)

Fortis is unequivocal in stating that there is not a need for further process. Fortis is of the view that there are fundamental differences among the parties and "that is precisely the time when the Commission needs to come in and make a decision" (T8:1474).

Commission Determination

In the words of COPE, "between the interveners in this process, there were some significant commonalities in their evaluation of the PBR, not the least of which was the universal opposition to the particular set of applications…."(T8:1456). The Commission Panel does not disagree and considers the proposals as put forward by the Fortis Companies to favour Fortis. The discussion of evidence put forward in this proceeding, which follows in Section 2.0, bears this out.

The submissions of the parties seem to suggest that the concerns of the parties are not with a PBR itself but with the specifics of the Applications put forward by the Companies. CEC made this clear in its opening statement at the Oral Hearing, noting that it would provide recommendations on how the proposed Application could be improved during the oral hearing and in its Final Arguments. Its lengthy Final Argument listed many concerns with recommendations as to how they should be addressed. It thus appears that CEC's concern is not with whether a PBR should be established, but with how the PBR elements should be more balanced in the interest of all stakeholders. Of the Interveners, only ICG and IRG are firm in not wanting to move forward albeit for different reasons. Of the remaining parties who commented, all seemed to favour some form of cost of service arrangement for the short term and a process to bring the parties together to discuss some form of PBR alternative for the future.

The Commission Panel notes that considerable time and money has been spent to conduct this PBR proceeding. Over the course of the past year, the parties and the Commission have read through the Applications, volumes of Information Requests (IRs), and considered the evidence, both oral and written, from a number of expert witnesses. The evidentiary record on which to base a decision is substantial. Add to this the level of differences among the parties with regard to various aspects of the PBR proposal and it is questionable whether any value will result from further process. **Therefore, the Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.**

In moving forward with this PBR Decision the Panel has a number of concerns.

The Commission Panel is not looking at this Application from a short-term viewpoint. We see an opportunity to make significant change over the long term with the way regulation is conducted in this jurisdiction and the way in which revenue requirements are determined. What form this may take is at this point undecided. Standing in the way of this is the lack of trust among the parties. If moving forward with an initiative like this PBR is going to work for the future the level of trust must be addressed and increased. To address this, the Commission Panel, in its Decision, has included a more lengthy discussion of the Annual Review Process than perhaps many of the parties anticipate. We have made significant changes to the purpose, content and process for this important program element. This will be discussed further in Section 2.3.6.

Much has been said by the parties about the improved regulatory efficiency that will result from a PBR process. Fortis seems to view PBR as a period where it will be required to provide only limited information as to its activities and savings it has achieved. This is a sticking point with interveners who are outspoken in their concerns with respect to the level of scrutiny and oversight of the activities of FEI and FBC over the PBR period. The Commission Panel acknowledges that improving regulatory efficiency is a desired outcome but due to the current levels of trust, the achievement of major regulatory savings in the first few years of PBR may not be possible or even advisable.

Looking at regulatory models more broadly, the Commission Panel accepts that there is no perfect regulatory process. The COS model has been relied upon in this jurisdiction and others with some success. The interveners may take comfort in the fact that one of its advantages is that it requires more frequent rebasing and hence there is a limit on the time before any sustainable savings directly impact customer rates. However, with COS regulation, there is little incentive to make sustainable efficiency gains and even less so when an investment is required. In fact, perversely, the utility may be incented to make unsustainable savings. On the other hand, the PBR model comes with its own set of inherent problems. If the wrong base is set for O&M or capital, or inappropriate I- or X- Factors are set which favour either party, it can result in additional gains for that party over a longer period of time unless an off-ramp is tripped.

Regardless of the method chosen, to be successful over the longer term the parties need to feel that their concerns are heard and where reasonable, acted upon. To facilitate this, the Commission Panel has taken steps in this Decision to ensure there is ongoing communication between the parties, which will result in greater transparency.

1.6.1.2 A Fair Rate of Return Under PBR

Fortis has relied on a number of guiding principles in developing its PBR Plan proposal. One of these states: "The PBR Plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return" (FEI Exhibit B-1, p. 43; FBC Exhibit B-1, p.39). Whether rates are set under cost of service or a PBR Plan, the Commission remains tasked with setting just and reasonable rates under sections 59 to 61 of the UCA.

As reflected in section 59(5), just and reasonable rates must represent:

- a 'fair and reasonable charge for service of the nature and quality provided by the utility' and
- a 'fair and reasonable compensation for the service provided by the utility' (Fortis PBR Final Argument, p. 17).

Fortis submits that this includes the well-established right of a utility to earn a fair return and the assessment of the PBR plan needs to be on a holistic basis as rate levels are a product of the plan elements working in tandem to yield a revenue requirement. Fortis' expert witness, Dr. Overcast describes the concept of just and reasonable rates in a PBR context as follows:

> "The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level…."
> (Exhibit B-1-1, Appendix D2, p. 7)

Fortis considers Dr. Overcast's description to be reasonable and submits that for the PBR plan to meet legislative requirements, three conditions must be present:

- An appropriate base on which to apply the PBR formula;
- A plan which has been crafted with a recognition of the extent to which costs are controllable by the utility; and
- The I-X formula applicable must realistically portray inflation impacts and other productivity factors impacting the X Factor and the I-X formula result must be reasonably achievable (Fortis PBR Final Argument, pp. 17–18).

Commission Determination

The Commission Panel is in agreement with Fortis that the revenues driven by the PBR formula must provide utilities the opportunity to earn a fair return. The Panel also acknowledges that changes to individual plan components "may change the overall risk/reward profile of the PBR Plan." The UCA addresses this in section 60(1)(a):

> In setting a rate under this act
> (a) the commission must consider all matters it considers proper and relevant affecting the rate,

(b) the commission must have due regard in the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59…

Fortis has put forward a PBR plan with numerous elements. As outlined by Dr. Overcast, each of the elements needs to be scrutinized carefully. This is to ensure they are reasonable and do not favour either the Companies or the ratepayer. Determinations resulting from this evaluation need to achieve a proper balance of risks and rewards between the Companies and the ratepayer and reflect current reality.

FEI and FBC's Applications have provided forecasts for O&M and Capital for the period 2014 to 2018. The Companies compare these forecasts against outputs from their proposed PBR mechanism and show that there are similar patterns between their forecasts and the amounts generated by the proposed PBR mechanism. Fortis takes the position that this similarity of pattern or balance must be maintained with any changes that the Commission may make to the formula. The Commission Panel notes that the validity and accuracy of these forecasts has not been established. Therefore, there is no basis on which to justify this comparison between the PBR mechanism and the Fortis forecasts. While there is a need to holistically consider the effects of changes to the PBR mechanism on the Companies' ability to earn a fair return, the Panel places no weight on the Fortis assertion that Commission changes must be balanced against what the Companies have submitted. Accordingly, the Commission Panel finds there is no requirement to balance Commission adjustments to the PBR against the revenue requirement forecasts provided by Fortis.

1.6.2 Amalgamation of Fortis Energy Utilities

FEI has expressed its intention to include FortisBC Energy Vancouver Island Inc. (FEVI) and FEW in the PBR starting in 2015. FEI witness Ms. Roy states that none of the items related to the PBR methodology are impacted by amalgamation. Ms. Roy continues by stating: "The delivery rates for 2015 will be set in the Fall 2014 annual review, at which time we will address adjustments to the

O&M and capital formula base, that's the dollar of the base, that are required to add in Whistler and Vancouver Island" (T2:246–247).

The Commission Panel notes that there were a number of concerns raised by the Commission with regards to FEVI's actual O&M and Capital spending as compared to approved amounts in the FEVI 2014 Revenue Requirements Decision.[1] Given these concerns, **the Commission Panel directs FEI to provide a detailed review of the historical expenditures of Capital and O&M for FEVI and FEW and a formal proposal for including FEVI and FEW within the PBR**. This will include, among other things, justification for its proposed additions to base O&M and Capital in consideration of the amalgamated FEU. This proposal must be filed within 60 days of the date of this decision. Further process will be determined at that time.

[1] FEVI 2014 Revenue Requirements Decision Dated May 23, 2014, Order G-65-14, Executive Summary, p. ii.

2.0 FORTIS PBR DESIGN

2.1 Background

2.1.1 Experience with PBR

FEI has had experience with a formula driven PBR regime operating two previous PBR plans; one in 1998–2001 and a second in 2004–2009. It reports that both of its previous plans were successful and building on this it has incorporated many of the elements of previous plans in the current PBR proposal. In addition, it has made adjustments to these as appropriate.

FEI states that a formula-based approach to "O&M was first adopted in FEI's 1994–1995 settlement and refined in the 1996–1997 settlement." The focus of the initial 1998–2001 plan was on operating and maintenance efficiencies with a limited capital mechanism. In addition SQIs were introduced and tracked to ensure the maintenance of service quality.

The 2004–2009 plan resulted from a negotiated settlement and was based on the previous plan in many aspects. O&M and capital expenditures were escalated by formula that incorporated inflation and productivity factors and included a 50/50 sharing mechanism between customers and shareholders. The 2004 Plan also incorporated some new elements. These included a longer term, a greater capital incentive, results oriented SQIs and an Efficiency Carry-over Mechanism (ECM) designed to encourage pursuing efficiency gains throughout the PBR term. (Exhibit B-1, p. 34)

2.1.2 PBR Approaches

Approaches to PBR fall into two broad categories: price caps and revenue caps. Under a price cap formula, rates are a function of two factors; the previous year's rates and a formula which is applied to those rates. Typically, the formula accounts for inflation (or an I-Factor) and an efficiency factor (referred to as the X-Factor) and may also include other terms to account for such things as growth, flow through items and exogenous events. The revenue cap approach differs from this in that it is the utilities' allowed or authorized revenue that is subject to the formula.

While both of these methods serve to create incentives to reduce costs and raise efficiency, they differ in the way they treat energy demand and incremental sales volumes. Under the price cap model the utility takes on the risk for demand variations. Therefore, they are encouraged to maximize sales volumes to the point where their marginal revenue equals their marginal costs. Given its continuing decline in sales per customer, FEI considers this to be problematic and unfair noting that this method is more appropriate for utilities with a demand trend that is stable and growing. Under a revenue cap model as is proposed in this Application, allowed revenue is decoupled from demand which provides the utility protection against such variation in demand.

Revenue Cap plans are typically further broken down into either a “building block” approach or a “total expenditure” approach based on their rate base assessment methodology and the role of the formula in establishing costs. Under the building block approach O&M and capital expenditures are assessed separately and in some cases some or all capital expenditures are handled outside of the formula. The separation of capital from O&M expenditures is a key distinction in comparing the two approaches. In contrast, the total expenditure approach, combines O&M and capital expenditures under one factor. FEI states that in most cases “the majority of PBR plans end up as hybrid systems where part of the capital expenditures (such as significant sustainment capital) is treated outside the PBR formulas and the rest of capital expenditures and O&M expenditures are determined under indexing formula and the productivity factor.” FEI further states that the removal of sustainment capital from the formula results in the large negative impact of infrastructure replacement on TFP being reduced or eliminated. (Exhibit B-1, pp. 29–30)

However, the building block approach does not allow the utility the same amount of flexibility to substitute capital expenditures for O&M, and vice-versa, as does the more traditional revenue cap model.

FEI's Proposed O&M Formula:

$$OM_t = OM_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *OM=Operating and Maintenance Expense subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

(Source: FEI Exhibit B-1, p. 57)

FEI's Proposed Growth Capital Formula:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

(Source: FEI Exhibit B-1, p. 62)

FEI's Proposed Sustainment and Other Capital Formula:

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

(Source: FEI Exhibit B-1, p. 64)

(Note: Fortis also describes two additional components; an exogenous factor (Z) and a flow through (Y) but does not include them in the formulas. However, they must be added to the formula above in order to establish FEI's total revenue requirement.)

These formulas provide the basis for calculation of FEI's operating and maintenance expense and capital calculations over the PBR term.

Commission Discussion

The Commission Panel accepts the Revenue Cap approach proposed by Fortis. Further the Commission Panel accepts the building block approach proposed by FEI. It is consistent with the approach taken in previous PBRs, and, as such has a "track record". Further, no Intervener takes issue with it.

The Commission Panel also generally approves the formulas proposed. By this we mean that the proposed formula components: an Inflation Factor, a Productivity Factor, Exogenous and Flow through items and a growth term based on average customers may be appropriate for inclusion. Further, the Panel takes no issue with the way Fortis proposes to combine the formula components.

We will examine the various proposed components in these formulas in greater detail later in this section and make determinations on each of these components. In addition, various other components of the FEI PBR proposal will be examined. These include the Earnings Sharing Mechanism, the Efficiency Carry-Over Mechanism, Service Quality Indicators, Review Processes and Off Ramps. These will be reviewed and determinations made. Collectively, these mechanisms will provide guidance and structure to the operation of the PBR over its term.

2.2 The PBR Formula Components

2.2.1 Setting the PBR Term

FEI and FBC have applied for a five-year term (2014 to 2018) for their PBRs. Fortis asserts that this is a reasonable term for the PBR Plan for the following reasons:

- It is a commonly adopted term for PBR's in North America;
- It promotes regulatory efficiency by reducing the number of comprehensive revenue requirement reviews; and
- It provides an adequate period of time to allow Fortis to realize cost savings resulting from efficiencies flowing from capital investments and other efficiency initiatives.

(FBC Exhibit B-1, p. 41; FEI Exhibit B-1, p. 45)

Fortis recognizes that a longer PBR plan poses risks to both the utility and its customers but believes that these risks are mitigated by other elements of the plan such as exogenous factors, re-openers and off ramps. It further asserts that the annual and mid-Term review processes will assure transparency and allow regular opportunities to assess the PBR plan.

In their Applications, Fortis draws attention to the B&V Report, which endorses the five-year term as being appropriate given the various elements in the plan. For example:

> "While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable."

(FEI Exhibit B-1, pp. 45–46; FBC Exhibit B-1, pp. 41–42; Fortis Exhibit B-1-1, Appendix D1, p. 36)

Intervener Submissions

CEC's view is that the five-year term proposed by the Companies is not appropriate. CEC states:

> "Theoretically, and as indicated in the AUC decision, the appropriate balance for a PBR plan lies in ensuring the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues become substantially out of sync with its costs or to create considerable gains or losses for stakeholders." (CEC PBR Final Argument, p. 17)

In CEC's view, the five-year term does not strike an appropriate balance as the risks to ratepayers are significant in a five-year term. CEC raises a number of concerns including:

- The claimed 'benefits' set out by Fortis are not supportable;
- There is a benefit to stakeholders if there is more frequent rebasing;
- There is a loss of transparency when costs and revenues are not scrutinized for five years rather than after two years under cost of service regulation;
- There is a loss of some assurance that the Utilities costs and revenues are prudent; and
- The five-year term exposes the ratepayer to:
    - Increased potential for miscalibration of the PBR plan resulting in increased risk;
    - Increased forecasting and estimating uncertainty and error;
    - Increased risk to principles of fair return on capital and recovery of prudent costs; and
    - Increased risk that the costs of the PBR plan will exceed any real benefits.

(CEC PBR Final Argument, p. 17)

CEC notes that PBR terms of three or four years are not unusual, although it acknowledges that those jurisdictions presented in the application are all for five years. CEC further disputes that the cost savings resulting from less frequent revenue requirement hearings are not necessarily a benefit to ratepayers in that revenue requirements have customer benefits and should not be eliminated simply to eliminate the expense of a revenue requirement proceeding (CEC PBR Final Argument pp. 20–21). CEC further suggests that the PBR proceedings will be significantly more expensive than an RRA proceeding and recommends the Commission carefully review the cost effectiveness of PBR relative to cost of service.

CEC challenges Fortis' claims that the longer PBR period is necessary to allow a broader set of efficiency projects to be considered for improving efficiency. CEC contends that efficiency investments may be undertaken within shorter time frames under Cost of Service if properly timed. It also asserts that Fortis has failed to give specific examples of efficiency projects that require a five year time period. CEC recommends that efficiency improvement projects could be brought forward at the Annual Review to allow them to be developed to ensure the required payback was available. This would create greater certainty for both the Companies and the ratepayer (CEC PBR Final Argument, p. 26). CEC also suggests that the issue of payback term could be better addressed through the use of deferral accounts which would not limit payback to any particular term. (CEC PBR Final Argument, p. 23).

With respect to Fortis' claim that the risks to customers and the lack of regulatory transparency under the PBR Plan is mitigated by checks and balances such as the use of exogenous factors, re-openers and off-ramps, and opportunities to review the operation of the plan throughout the term, CEC claims that there is little value to the ratepayer afforded by these checks and balances and they do not provide openness or transparency (CEC PBR Final Argument, p. 25).

CEC recommends that in the event the Commission approves a PBR, they approve at most a three-year term (CEC PBR Final Argument, p.26).

ICG believes that Fortis has not adequately justified a five-year PBR plan and recommends that if a PBR plan is approved, it should have a two-year term.

ICG concludes that:

- Efficiency investments, if any, are not as finely tuned to the regulatory regime as to justify the need for a five year PBR plan; and
- A five year PBR plan should only be approved for a utility with rate stability closely following inflation. ICG believes this may be the case for FEI but it is not the case for FBC. (ICG Final Argument, pp. 16–17)

Fortis Reply

Fortis refutes the CEC recommendations for the following reasons:

- Given that a decision will not be forthcoming until the second half of 2014, CEC's recommendation for a three year term is, in effect, advocating a two year term which would restrict the potential for efficiency investments to no greater than would occur under a two-year RRA;
- The shorter time period would also suggest a lower X-Factor providing customers with less upfront benefits;
- The CEC claims regarding increased forecasting and estimating uncertainty and error is erroneous in that PBR formula inputs and flow-through items will be re-forecasted annually in the fall of the preceding year, as opposed to preparing two-year forecasts in the spring before the first year of a two-year Cost of Service test period;
- The AUC,PBR Decision stated:

> "The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America." (para 836)

- Under PBR, the benefit of embedding cost savings is not lost, it is only delayed. Furthermore, there is an opportunity under PBR to generate greater benefits.

(Fortis PBR Reply, pp. 28-30)

Fortis responds that ICG's view — that efficiency investments are not as finely tuned to the regulatory regime so as to justify a five-year PBR plan – is a backwards approach to analyzing the term. In Fortis' view the PBR is about creating opportunities to find efficiencies. The term selected should maximize these opportunities while balancing this with the need for periodic rebasing.

Trying to identify the shortest term necessary to make already identified opportunities viable is not the correct approach. In Fortis' view a shorter term "reduces the power of the incentive for management to find – using economic terms – the best available combination of inputs to produce outputs. There is an opportunity cost to customers associated with a shorter term, which ICG is ignoring."

Fortis makes the following counter-points to ICG's assertion:

- ICG has not cited any evidence in support of the notion that PBR cannot work in the context of a utility that has recently been experiencing rate increases higher than inflation;
- The evidence of Drs. Overcast and Lowry would suggest that the scenario envisaged by ICG merely suggests that the X-Factor for the utility will tend to be negative;
- FBC's recent rate trajectory has been driven by investment in asset replacement and reinforcement projects and the cost of energy to meet customer demand. FBC's proposed PBR plan accounts for such circumstances by excluding lumpy capital from the formula and by flowing through variances in power purchase expenses.

(Fortis PBR Reply, pp. 27–28)

No other Interveners took positions on the length of term of the PBR.

Commission Determination

Both CEC and Fortis agree that a major factor in determining the appropriate length of time for a PBR is to find the balance between a time period that is adequate for the companies to find and pursue opportunities for efficiencies that will benefit both the shareholder and the ratepayer and not being so long as to put either party at risk.

Fortis asserts that the design of the plan puts in place checks and balances, such as regular re-forecasting of certain elements within the PBR formula, annual and mid-term reviews providing an opportunity to assess how well the plan is working, and re-openers and off-ramps to deal with possible failings of the plan. CEC asserts that these checks and balances will be ineffective in protecting ratepayer interests and in addition there are transparency and prudency concerns.

Efficiencies that require significant upfront costs in order to deliver a stream of benefits over a period of years are, in the Panel's view, more likely to be pursued under a PBR with a longer time period. The Panel is not persuaded by the assertions of CEC and ICG that a longer time period for the PBR plan is of little or no value to Fortis' pursuit and implementation of efficiencies. Nor is the Panel persuaded that a five-year PBR plan can only be implemented for utilities with rate stability closely following inflation.

In the Commission Panel's view, the time frame for the PBR plan is appropriately determined by assessing the time period over which the Companies are incented to maximize input efficiencies while the ratepayer and the utility are protected from unwarranted gains or losses. In choosing the time frame for the PBR, we consider the ability of the checks and balances to provide stakeholders with appropriate protection. Elsewhere in this Decision, the Panel directs Fortis to make changes to certain mechanisms, which will strengthen Fortis' proposed checks and balances in order to adequately protect stakeholder interests.

While the Commission Panel finds that with the changes it has directed to the mechanisms that protect stakeholder interests, a five-year PBR term is appropriate, it must be recognized that a substantial portion of year one will have passed without the certainty provided by this Decision. The effect of this would be a PBR term that is only a little over four years. **In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.** This six-year term ending in 2019 should better enable Fortis to find efficiencies that will benefit all parties.

2.2.2 Setting the I-Factor

An inflation, or I-Factor, has been included in the mechanism to provide recognition that utility costs are subject to inflationary costs occurring in the economy. In this Application, Fortis proposes to use a weighted composite I-Factor for O&M with labour at 55 percent indexed to the BC-AWE and non-labour at 45 percent indexed to the BC-CPI which reflects Fortis' current ratios of labour to non labour. These would be based on forecasts for the coming year for both indexes. For BC-CPI, the average of six forecasts is relied upon. Fortis considers the use of a composite labour and non-labour inflation index to be more reflective of Company costs, which have both labour and non-labour components, rather than relying solely on an economy based inflation measure such as CPI. Moreover, Fortis reports that other jurisdictions have relied upon these two indexes in developing I-Factor estimates.

In selecting these inflation indexes, Fortis considered alternatives on the basis of whether they are:

- Indicative of changes in inflationary pressures that the utility expects to experience;
- Readily available and published by a reputable, independent agency;
- Transparent and easy to understand; and
- Reasonably stable.

Fortis intends to update both the BC-AWE and BC-CPI rates each year as part of the Annual Review process stating that this is more preferable to truing-up forecasts to actual because it more closely reflects the cost pressures of the utility. In explanation, Fortis argues that this methodology applies to both labour and non-labour costs. (FBC Exhibit B-1, pp. 42–44; Fortis Final Argument, pp. 62–67)

Intervener Positions

CEC states that the 55 percent to 45 percent labour/non-labour weighting places too much weight on the labour component particularly for FEI capital. CEC states that the percentage of labour to non-labour for FEI in the last five years has been consistent at "45% to 55% then reversing in 2012 to 55% to 45% and has declined from 54 percent to 46 percent in 2012." Capital has been more inconsistent "in the 22% to 78% range ending in 2012 at 24% to 76%." For FBC, the actual O&M labour to non-labour was 54 percent to 46 percent in 2012, with the capital labour to non-labour ratio 67 percent to 33 percent. (CEC Final Argument p. 35; FBC Exhibit B-11, BCPSO 1.26.3; FEI Exhibit B-6, BCPSO 1.13.2)

In addition, CEC raises a number of issues with the Fortis methodology for determining the I-Factor:

1. Actual vs Forecast Inflation — CEC argues that the Fortis approach results in a consistent bias toward over forecasting. Analysis of the inflation forecasts being used indicates that over the last nine years, the CPI has been over forecast on average by 0.38 percent annually and by 1.4 percent annually on a compound basis. CEC submits that the AUC approach of adopting the previous year's actual is preferable to the Company's approach of using forecasts, embedding errors and compounding them over time. (CEC PBR Final Argument, pp. 29–33)

2. Impact of Forecast Timing on Adequacy – CEC takes issue with the inflation forecasts they intend to rely upon and the timing of published data. CEC argues that during this proceeding, Fortis' submission of more updated information resulted in a 10 percent reduction in the inflation forecast.

3. CPI Systemically Overestimates Inflation – CEC argues that when using CPI as a measure of inflation, there are 4 systemic biases; commodity substitution, outlet substitution, new goods and quality adjustment bias. CEC cites a number of studies that estimate the bias effect to be 0.5 to 0.6 percent. Dr. Lowry concurs with a CPI bias of close to 0.5 percent and offers the GDP IPI as a solution. CEC submits that Dr. Lowry's evidence on GDP IPI indicates it is the best macroeconomic indicator.

4. Overweighting of Labour to Non-labour – CEC contends that the labour AWE (which is typically higher than the CPI) is over weighted relative to the non-labour portion particularly when it comes to capital. Moreover, when considering the Conference Board of Canada overestimates of CPI and AWE, its estimate of AWE is 100 percent greater than the amount AWE actually exceeds CPI 0.61 to 0.31 percent). It therefore concludes that the proposed methodologies will overestimate inflation. (CEC Final Argument pp. 29–35)

PEG states that if the Commission wishes to use a macroeconomic output price index in the inflation measures for the Fortis utilities either the CPI-BC or the Gross Domestic Product Implicit Price Index times Final Domestic Demand (GDPIPIFDD) for BC is recommended. It indicates that both of these are reflective of local BC conditions. (FEI Exhibit C1-9, p. 51) PEG recommends that if the Commission is to approve escalation indexes for capital expenditure budgets, industry-specific indexes are warranted. PEG states that inflation in power and gas utility construction can deviate significantly from macroeconomic measures noting that there has been a slowdown in electricity construction inflation since 2011. In its view, the risk of overcompensation exists if the Commission is to adopt the inflation indexes proposed by Fortis to be applied to capital expenditures. PEG discusses a range of indexes to estimate Canadian construction costs and states "[it] can be seen that the summary EUCPI for power distribution did a fairly good job of tracking the trend in the CSPI for engineering structures…On the basis of this comparison, we recommend the EUCPI for power distribution as the best available measure of the trend in gas utility construction prices." Later in its evidence, PEG suggests that a 50/50 weighting between the EUCPI power distribution and power transmission indexes would be sensible for FBC. Based on a review of the Canadian non-residential building cost price indexes, PEG notes that Vancouver prices lag behind Canada as a whole by 50 basis points annually and states that it would be reasonable to reduce EUCPI growth rates by a similar amount to reflect the local economy. (FEI Exhibit C1-9, PEG Evidence, p. 51)

With respect to the weighting of labour vs materials, PEG states that care must be taken to ensure the labour cost weighting is equal to the share of direct labour expenses and views the proposed 55 percent as being too high with reference to capital cost or total cost. (Exhibit C1-9, p. 52)

BCPSO argues that the I-Factor should be trued-up to actual because it is uncontrollable and hence, should be flowed through. It notes that if actual prices are different than forecast, the utility will either win or lose and the result will have nothing to do with a gain or a loss in efficiency. BCPSO also takes issue with the Fortis argument that its costs are based on forecast inflation rather than actual inflation due to the timing of purchases. It asserts that actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts. BCPSO takes no position on the use of a composite I-Factor relying upon the BC-CPI and the BC-AWE. (BCPSO Final Argument, para. 41–44)

ICG states that it takes no position on the I-Factor because it does not consider it to have a material impact on rates. (ICG Final Argument, p. 23)

Fortis Reply

Fortis submits that the rationale for its proposal is consistent with COS and prior PBR principles and asserts that there is nothing to justify the approach proposed by Interveners. Fortis asserts that CEC has provided no evidence that the BC GDPIPIFDD or BC-CPI alone is more reflective of actual Fortis labour costs than the BC-AWE and CEC's opposition to the use of BC-AWE is because labour indexes rise more quickly than corresponding macroeconomic indicators. In its view, if the Commission were to adopt a measure that reflects labour inflation to a lesser degree, it would result in a bias in favour of customers. (Fortis PBR Reply, pp. 55–56)

Fortis also takes issue with CEC's characterization of labour/non-labour weightings and argues they are more characteristic of the base year and not historical years. In support of this, Fortis points out that the increase in the O&M labour weighting occurred in 2012 when customer care was insourced. This reversed costs between the two categories. In addition, Fortis notes that CEC's percentages do not reflect the contractor labour in the non-labour category. When contractor labour is considered, the 55 percent labour weighting is supported. Fortis also points out that in spite of CEC's opposition to a labour specific inflation measure, its expert, Dr. Lowry "modified his recommended I-X formula for FEI's O&M to include a 55 percent BC-AWE weighting." (Fortis PBR Reply, pp. 56–57)

Fortis does not dispute the average annual variance of 0.38 percent between forecast and actual CPI yields. However, it does argue that the compound annual variance of 1.4 percent for BC-CPI is unsubstantiated and should be disregarded. However, Fortis provides no alternative calculation. (Fortis PBR Reply, pp. 59–60)

Fortis considers forecast inflation as reflective of the cost challenge faced by companies and arguments in favour of a true-up or reliance on the previous year flawed. It points out, in reference to BCPSO's comments, that they are overlooking the fact that the I-Factor serves as a proxy for Fortis' inflation "not the economy as a whole." With respect to CEC's reliance on the previous year actuals, Fortis states that this is just another way of forecasting "which employs a simplifying assumption that the actual experience in the prior year is predictive of the future." In the view of Fortis, relying on the previous year as a proxy for the current year introduces lag rather than being forward looking. Fortis further states that applying the previous year's actuals to future forecasts result in greater under or over estimations of inflation. It provides a graphic demonstration of this showing the two methods and the effect of inflationary changes from 2008 to 2012. (Fortis PBR Reply, pp. 57–59)

Commission Determination

There are two interrelated issues to be addressed by the Commission Panel with respect to the determination of the I-Factor. The first of these deals with the basis on which the I-Factor should be set. Is it appropriate to use forecasts as proposed by Fortis, rely upon the previous year's actuals as argued by CEC or "true-up" to actual as proposed by BCPSO. The second is what indexes are most suitable to rely upon for the determination of the I-Factor. Related to this is consideration of the labour/non-labour separation. If separated, what is the appropriate weighting for each and whether the weighting ratio should be applied in the same manner for O&M and Capital expenditures?

i) Method to Determine I-Factor

From the evidence presented it is clear there is no perfect way to determine the I-Factor. Therefore, the best that can be expected is to derive a proxy that best estimates the impact of inflation on the Companies for the full PBR period.

The problem with the forecast approach proposed by Fortis is that there will almost always be a variance between forecast and actual. Fortis has not disputed this but has argued that its actual costs are very much influenced by forecast as they often make binding commitments in advance of a given year and these take into account forecasted inflation. The Commission Panel accepts that this may be the case but it is not unique to Fortis as actual inflation measures reflect this spending behaviour on a broader basis. BCPSO makes a similar point as it observes that "actual inflation differs from forecast inflation and therefore actual increases are not driven by forecasts." In the view of the Panel, a significant problem with Fortis' proposed reliance on forecast rates of inflation lies in the fact that any variances which do occur are compounded each year. This may not be too serious where there is some assurance that over time these forecast errors will balance out. However, this is not the case. Instead, it is reasonable to assume that over the PBR period future forecasts may be significantly skewed either up or down relative to actuals and, as stated by BCPSO, wins or losses may have little to do with gains or losses in efficiency. **Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.**

The BCPSO approach provides the most accurate measure but suffers from the fact that an actual number is not available until the year has been completed. Both Fortis and its ratepayers require a higher level of certainty as the year progresses and therefore the Panel does not support this approach.

While the approach, proposed by CEC, to rely on the previous year's actual index figures is backward looking and introduces lag, the Commission Panel finds this approach offers some significant advantages. It is based on actual numbers rather than a series of forecasts, none of which are trued up. This approach will ensure that over time the cumulative effect of the I-Factor will be close to actual index numbers. Given the importance of the I-factor on the I-X formula and its impact on future O&M and Capital forecasts over time, the use of actual numbers is of critical importance. While not forward looking, a reliance on the previous year's actual numbers will eliminate the impact of compounded errors that exists in the Fortis proposal. Moreover, the index numbers are available early enough in the year so as to give Fortis and its customers a level of certainty. **Given these advantages, the Commission Panel determines that the I-Factor used in**

the formula is the actual index results of the previous year. The Panel notes that this methodology has been employed by the AUC in its PBR.

ii) I-Factor Indexes

The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR. For non-labour expenses, the Panel notes that CPI indexes such as those proposed by Fortis (where an average of six BC-CPI forecasts were used in this proposal) are more commonly relied upon and indeed were approved by the Commission in past PBRs. Moreover, CEC has not presented sufficient evidence to support a move to the GDP-IPI and the Panel is not persuaded that a move away from the more commonly relied upon CPI based indexes is warranted. We do, however, accept that there is a distinction between labour and non-labour costs that is not satisfactorily captured in CPI indexes. Therefore, the Panel accepts the use of the BC-AWE index to capture labour costs and notes that its use seems to be supported by Dr. Lowry.

A matter causing considerable concern among Interveners is whether a 55 percent weighting to labour is appropriate. This issue is raised by CEC which recommends a lower labour component. The Commission Panel accepts the explanation of Fortis that FEI's O&M labour costs shifted in 2012 due to the insourcing of the customer care function which resulted in a 55 percent labour weighting going forward. The Panel also notes that O&M labour costs for FBC have ranged from 54 percent to 58 percent since 2008, which is close to Fortis' proposed 55 percent labour component. **The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.**

When applied to Capital Expenditures the matter is less clear. This is because, as Fortis points out, there is contractor labour in the non-labour line item. When included in the calculation, the inclusion of contractor labour brings the capital labour percentage up to 64 percent from 24 percent, which is higher than the proposed 55 percent for FEI. For FBC, the ratio of labour costs embedded in its capital expenditures has consistently been at 65 percent or higher.

The Commission Panel determines that the 55 percent to 45 percent labour to non-labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.

The Commission Panel has also considered Dr. Lowry's evidence in support of relying upon industry specific indexes for Capital expenditures as construction costs are not necessarily rising in the utility sector. While this may be the case, the Panel considers that there is insufficient evidence to suggest that capital costs for Fortis' sustainment and other projects are captured by Dr. Lowry's proposed indexes. Hence, a reliance on construction cost based indexes may not be a true reflection of actual costs and the Commission Panel is not persuaded a move to these indexes is warranted at this time.

2.2.3 Setting the X Factor and Stretch Factor

2.2.3.1 Introduction

Fortis states there are two different approaches that can be used to set the X-Factor, a Pure Total Factor Productivity (TFP) approach and a Hybrid Judgement-based approach. Under the pure TFP approach, the X-Factor is derived from rigorous mathematical models that calculate the growth of total factor productivity. In this approach, the X-Factor is ordinarily defined as the measured industry TFP growth plus an adjustment for any difference between the inflation index used in the PBR index formula and the rate of input price inflation for the regulated sector. (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Fortis describes the following elements as influencing the measured TFP growth:

1. *TFP growth estimator methodology*. Typically either an econometric modelling or an indexed based approach.
2. *The sample of companies*. As broad a sample as possible. Since it is impossible to ensure the firms in the study are "exactly compatible" it is important to consider the results of the analysis in the context of the specific utility in question and its proposed PBR plan.
3. *The measurement period*. In general, the most recent data should be used. The length of study periods from other North American jurisdictions is between five and 20 years.

4. *Choice of output measure***.** Ideally a comprehensive set of cost drivers should be used.
5. *Choice of Input Measures***.** Input measures should represent the operating and capital costs associated with the utility. Inclusion or exclusion of particular cost items may add to the bias of TFP estimates.

Fortis also states that "[i]n practice, the X-Factor values estimated through the pure TFP approaches are often adjusted to reflect circumstances of a specific company and by a judgement-based stretch factor." Although Fortis previously asserted that in the pure TFP approach, the X-Factor is derived from 'rigorous mathematical models,' it concludes that the result of a TFP growth study is "thus dependent on expert judgement in a number of areas." (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 45–46)

Under the hybrid judgement approach, "the mathematical derivations of the X-Factor, such as TFP studies, are still used as guidance for the determination of X; however, practical matters such as the actual effects of X on the company's bottom line and expected business conditions during the PBR term are also considered to determine a final measure." Fortis cites research that shows that the parameters that affect a regulated company's costs, revenues and risks should be considered and asserts that these parameters include items such as the PBR term, cost items subject to flow-through in customers' rates, the implementation of other sharing models such as earnings sharing mechanisms and the use of historical or expected performance as a basis for X-Factor estimation. (FEI Exhibit B-1, pp. 49–50; FBC Exhibit B-1, pp. 50–51)

Both Fortis and B&V utilize the hybrid judgement approach. B&V's studies resulted in TFP trends of approximately -4.0 percent to -5.0 percent, yet it recommends an X-Factor of 0.0 percent. B&V states that "[c]are must be taken in using the results of any TFP study values because the underlying assumptions of the study may not match the implementation of a proposed plan. The TFP calculated in this study includes an ex-post measure of capital that may differ from the capital treatment that separates a portion of capital such as CPCNs for treatment outside of the plan." (Fortis Exhibit B-1-1, Appendix D2, p. 1)

According to Dr. Overcast "even if you come up with a TFP number, there are some things that you would have to use your judgment on to reflect how that might impact the final X-Factor that you are going to recommend. This judgement is required because there is no way of 'separating out' CPCN and 'all of the other pass-through costs', from the total cost of any utility in the study" (T3:466). However, B&V provides no specific analysis of its adjustments to the TFP factor. B&V's recommended X-Factor is based on "several features of the overall plan that we believe reduce the negative TFP closer to zero. The 0% X-Factor would include a stretch factor as well" (FEI Exhibit B-11, BCUC 1.44.1).

Fortis does not accept the recommendations of B&V, and instead applies its own hybrid judgement approach to propose an X-Factor of 0.5% for each utility, stating that this "is well above the range specified in the B&V TFP report." According to Fortis, the reason it proposes to adopt a more challenging X-Factor is to account for Fortis' specific circumstances and the overall design of the PBR plan. In particular, Fortis' proposed PBR plan excludes large capital projects approved as CPCNs, and because the B&V studies cannot separate categories of spending "educated judgement is required to adjust the TFP value for the companies in the study." (FEI Exhibit B-1, pp. 52–53; FBC Exhibit B-1, pp. 48–49).

PEG provides the following formulaic description of its proposed X-Factor:

$$X = MFP^{N} + Stretch$$

stating that MFP^{N} is a multifactor productivity index that uses the number of customers to measure output. PEG explains that the term stretch reflects an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. PEG adds that "[t]his depends in part on the company's operating efficiency at the start of the PBR plan. It also depends on how the performance incentives generated by the PBR plan compare to those in force for sampled utilities during the index sample period." (FEI Exhibit C1-9, pp. 9, 70)

PEG describes the measure of productivity as:

$$Productivity = \frac{Outputs}{Inputs}$$

and further defines the multifactor productivity index as the change, or trend, in productivity:

$$trend\ Productivity = trend\ Outputs - trend\ Inputs.$$

(FEI Exhibit C1-9, pp. 9, 70)

As can be seen above, while PEG uses the term multifactor productivity (MFP) growth when assessing industry productivity growth, B&V uses the term TFP growth. PEG suggests that MFP growth is the correct term, stating that indexes are sometimes called TFP indexes but are better described as MFP indexes since multiple input categories are considered but some inputs *(e.g.* purchased power) are usually excluded. (FBC Exhibit C6-9 p. 57; FEI Exhibit C1-9, p. 57)

Dr. Lowry agreed that the terms MFP and total factor productivity (TFP) are used interchangeably, but commented that "[t]he reason that I prefer the term Multi-Factor Productivity is when one [does] these studies there are — almost always some utility costs that are excluded from the calculations. For example, even in the Black & Veatch work they excluded the purchase power costs of the utility." (T7:1347)

PEG does not address the issue of judgement based adjustments to the TFP trend results. However, with regard to the exclusion of pass-through costs, it states "Suppose, for example, that expenses for the procurement of energy are not addressed by the indexing mechanism of the PBR plan. These costs should then be excluded from the definition of cost used in the index research. Similarly, the exclusion of a sizable share of routine capex from the indexing mechanism may make it appropriate to exclude some plant additions from the MFP research." (Exhibit C1-9, p. 16)

Commission Discussion

In these Proceedings, the terms TFP and MFP have been used interchangeably. However, we note that in the strictest sense neither study dealt with all inputs so they are both reporting MFP trends. Nevertheless, we will use the terms interchangeably, but if context requires, we will differentiate between the two.

Further, after reviewing the evidence and submissions of parties, the Panel notes differing usage of the terms TFP/MFP and TFP/MFP *change* or *trend*. The four studies (one for gas utilities and one for electric utilities from B&V and from PEG) are designed to measure the *change* or *trend* in TFP/MFP, although the study results have been frequently referred to, by many parties, as TFP/MFP. The Panel will use the term *trend* in TFP/MFP when referring to study results. However, quotations from parties may not always contain consistent terminology.

B&V states that it utilizes the hybrid judgement approach, while PEG appears to use the pure approach. In both cases, the X-Factor recommendations are based on TFP/MFP trend studies. Fortis applies further judgement to arrive at its proposed 0.5 percent. Fortis describes the pure TFP approach as being derived from "rigorous mathematical models that calculate the growth of total factor productivity." However, a considerable amount of judgement was involved in both studies regarding assumptions such as study length, input and output criteria.

The essential difference between B&V and PEG's approaches is that B&V applies a single adjustment to its resulting TFP trend to account for both a stretch factor and the fact that a number of flow-through costs are proposed in Fortis' PBR plans. In contrast, PEG explicitly excludes those flow-through costs from its study inputs. Further, PEG makes explicit its assumptions concerning the stretch factor. This eliminates any need for a judgement based adjustment to the MFP trend result.

In this Decision, the Panel will examine further the underlying assumptions applied by each of the experts, in addition to the judgement-based factors applied by Fortis that underlie its X-Factor recommendations. The Panel will take the following approach:

1. Establish a measure of the MFP/TFP trend upon which to base the X Factor.

   There was considerable disagreement between the two experts concerning TFP/MFP trend study methodology. The Panel notes the submission of CEC that "the Commission has a serious problem with the evidence. The differences of opinion are not straight forward and understandable but are tied into esoteric economic theory and debates about methodology and assumptions, for which only PhD's seem to have perfunctory conclusions" and that "one of the most serious questions for the Commission to resolve is whether or not it is really suitable to impose this morass of complicated debate into the rate making process." (CEC PBR Final Argument, p. 57) We find CEC's comments curious, given the fact that it is referring, at least in part, to its own witness.

   To this, Fortis replies that "The Commission is capable of weighing the expert evidence and coming to a considered decision, and should do so." (Fortis PBR Reply, p. 64). The Panel agrees with Fortis. Accordingly, in establishing the measure of TFP growth, we will examine the report submitted by B&V as part of Fortis' Applications, in addition to the report submitted by PEG for CEC.

   The Panel agrees with Fortis that the result of a TFP growth study is dependent on expert judgement. However, in this proceeding, because there is considerable disagreement between the two experts in many of the study areas, where this occurs, the Commission Panel will assess the differing opinions and we will rely on our own judgement.

2. Apply any adjustments to the TFP that may be required before applying a stretch factor. Fortis states that an adjustment to account for inflation may be required. In addition, the Panel will consider any changes that arise from criticisms, made by the parties, that we have accepted.

3. Consider, to the extent the Panel finds appropriate, the TFP findings made by the AUC and the OEB as described in the Jurisdictional Benchmarking Report submitted by B&V.

4. Apply a stretch factor. As part of its determination of a stretch factor, the Panel will consider available evidence from the previous PBR period and the X-Factor that was applied during that period. We agree with Fortis that a stretch factor is judgement based and will use our judgement to determine one that is appropriate.

5. Consider any other parameters that may be appropriate in the determination of the X-Factor. This may include consideration of the elements of Fortis' proposed PBR Plan along with any other specific circumstances of Fortis. This also includes X-Factor evidence from

other jurisdictions. Here, the Panel will apply its judgement as to what extent this evidence is relevant to the determination of the X-Factor in this Proceeding.

2.2.3.2 The B&V Studies

2.2.3.2.1 Overview

The B&V TFP trend studies (one for gas utilities and one for electric utilities) were prepared for Fortis. The gas utility database consists of 95 utilities operating in 30 states in the United States (US) for the period 2007 through 2011, which, according to B&V, is the latest available five-year period for the data. The utilities' customer bases range from 86 for Brainard Gas in Ohio to 5,549,399 for the Southern California Gas Company. The sample companies have varied operating histories and include some that have been in existence for over 150 years and others that have been in existence for less than 20 years. There is also a mix of utilities that require transmission main and those that do not. Pacific Gas and Electric Company has 5,744 miles of transmission main while a number of utilities have none. (FEI Exhibit B-1-1, Appendix D2, p. 2)

The electric utility data base consists of 72 electric utilities operating in the US for the period 2007 through 2011, which, according to B&V, is the latest available five year period for the data. The utilities' customer bases range from 28,372 for Fitchburg Gas & Electric Light Company to 5,278,738 for Pacific Gas & Electric Company. The companies operate in different regulatory environments including bundled and unbundled environments.[2] (FBC Exhibit B-1-1, Appendix D2, p. 2)

B&V states that its methodology is based on the use of a production function, which "underlies the estimate of TFP because each level of output corresponds to the different set of inputs required to

[2] In a bundled environment, commodity costs and delivery costs are combined. In an unbundled environment, they are separated.

produce that output." It states that the "production function defines the relationship between the dependent variable output and the independent variables of capital and labour, which make up the factors of production." (FEI&FBC, Exhibit B-1-1, Appendix D2, pp. 2, 10)

To calculate inputs, B&V measures the ex-post cost of capital, including return, depreciation and taxes, using Operating Revenue excluding gas costs and all other operating and maintenance expenses. It states that the calculation of this cost is based "on a method that the Federal Energy Regulatory Commission (FERC) refers to as the *Kahn Method."* The measure of all other costs is "a direct composite measure as reported in the financial reports of each company." (Fortis Exhibit B-1-1, Appendix D2, pp. 2, 10)

Dr. Overcast has not previously conducted a TFP trend study, although he testified that he had contracted Dr. Lowry to provide such a study (T2:289–290). Fortis states that "Dr. Overcast used his understanding of utility business economics and operations to design a reasonable TFP methodology that addressed shortcomings with applying the traditional TFP model to regulated gas and electric utility industries that do not fit the academic paradigm" (Fortis PBR Reply, p. 69).

B&V's studies are criticised by PEG on a number of grounds. In particular, Dr. Lowry states that the Kahn method is designed to calibrate the X-Factor given a specific inflation measure and not to estimate the MFP trend. The principle areas of criticism are:

1. Improper approach to Output Measures;
2. Improper approach to Input Measures;
3. Use of arithmetic vs logarithmic growth rates; and
4. Study time period.

(FEI Exhibit C1-9, p. 73)

In many cases, PEG has calculated corrections to B&V's reported TFP trends, to account for these purported errors. However, PEG states that it does not believe that the corrected results are of sufficient quality to serve as the basis for X-Factor calibration. “For example, we are still concerned that the sample period is too short and that costs are included in the study that should be excluded.” (FEI Exhibit C1-9, p. 62)

Fortis submits that “[t]he ‘corrections’, when examined closely, are revealed to be changes in Dr. Overcast’s assumptions to match Dr. Lowry’s own assumptions.” It further submits that “‘corrections’ are meaningless when Dr. Lowry’s assumptions do not approximate reality.” (Fortis PBR Reply, p. 74)

The B&V study results are shown in Table 2.1:

Table 2.1 B&V TFP Trend Results

	Gas Utilities	**Electric Utilities**
Average TFP Trend	-4.1%	-4.9%
Range	-3.2% to -4.9%	-3.9% to -5.5%

(Source: Fortis PBR Final Argument, p. 74)

B&V states that the TFP trend results derived from the studies “are theoretically sound and produce results consistent with the logical foundations of TFP analysis and the operating realities of electric [and gas] utilities.” In its view, the results are reasonable as the foundation of an electric TFP value determination taking into account the utility specific elements of the plan. (Fortis Exhibit B-1-1, Appendix D2, p. 11)

As previously discussed, Fortis proposes an X-Factor substantially higher than B&V’s recommended X-Factor. Fortis acknowledges that the proposed X-Factor is “the one area where B&V and [Fortis] part company.” B&V states that based on its review of the factors outside the PBR such as CPCN capital and other provisions, it “felt that even zero is a stretch”. B&V regards this additional stretch factor as being more aggressive than is warranted. (FEI Exhibit B-11, BCUC 1.44.13; FBC Exhibit B-1, pp. 43, 48, 49, 53)

Commission Discussion

Of particular concern to the Commission Panel is Fortis' adoption of an X-Factor that B&V feels is "more aggressive than warranted." This suggests to the Panel that the studies' TFP trend results are too low to accurately reflect actual utility industry productivity trends. Accordingly, the Panel will examine the assumptions underlying the B&V TFP trend studies. The Panel will consider further Fortis' hybrid judgement approach to setting the X-Factor in Section 2.2.3.5 of this Decision.

PEG makes a number of comments and criticisms concerning specific assumptions underlying B&V's studies and proposes corrections to the results. These corrections, comments and criticisms also suggest that the B&V Study results are too low. To the extent that these criticisms are valid, this is further indication that B&V's results may be understated.

With regard to PEG's suggested corrections, the Panel acknowledges Fortis' argument that corrections that do not reflect reality are meaningless. However, if a correction is required to ensure that the study results do mirror reality, then those corrections are indeed meaningful. Accordingly, in the following sections of this decision, the Panel will further examine the assumptions underlying B&V's study, including PEG's critique of those assumptions and its proposed corrections.

2.2.3.2.2 Output Measures

For each of its studies, B&V proposes output measures that are a composite of the number of customers and capacity. These output measures are shown in Table 2.2.

Table 2.2 B&V Study Output Measures

Electric	Gas
Composite Output — Weighted by Electric Customers and Substation Capacity 60%/40%	Composite Output — Density-Weighted Number of Customers and Capacity

For the electric study, B&V states that it calculated its output measure (AH[3]) using the following formula:

$$AH = (AG*0.6)+(AA*0.4)$$

where AG = Customers Adjusted for Density and AA = Substation Capacity in MVA. (FBC Exhibit B-1-1, Appendix D2, Schedule 2 LDC Electric Utility Database)

For the gas study, the formula for the output measure (AB[4]) is:

$$AB = (AA*T)+[W*(1-T)]$$

where AA = Customers/Density Index; W = Total Capacity; and T = Distribution Customer Factor (Distribution Main 2" or less/Distribution Miles). (FEI Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database).

In both cases, B&V calculates the output measure for each year using the above formulas and then calculates the trend in output, or "% Output Change by Year"[5] (FEI&FBC, Exhibit B-1-1, Appendix D2, Schedule 2 LDC Gas Database & Electric Utility Database)

3 AH is the column heading for the output measure in FBC Exhibit B-1-1, Appendix D2, Schedule 2: Electric Utility Data Base.

4 AB is the column heading for the output measure in FEI Exhibit B-1-1, Appendix D2, Schedule 2: Gas Utility Data Base.

5 For the electricity study, % Change in Output 40/60 (column AI) = %Δ in AH. For the gas study, % Output Change by Year (column AC) =%Δ in AB.

PEG is critical of this approach, stating that:

> "[i]nstead of a proper output trend index, B&V calculated an output *level* index and then calculated its growth rate. In this case, the trend in the capacity index improperly dominated the trend in the number of customers served because of a different numeraire. One indication of the problem is that the estimated electric productivity trend would likely depend on whether substation capacity was measured in kVA or MV." (FEI Exhibit C1-9, p. 60)

B&V did not comment on this issue of the calculation of the output trend.

Commission Determination

The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon. In making this determination, the Panel considered the following example of Allette Inc. taken from B&V's Electric Utility Database. Table 2.3 shows B&V's calculation of the output measure for the years 2008 and 2009 which relies on the capacity measure in MVA.

Table 2.3 B&V Output Measure for Allette Inc. for 2008 and 2009

Year	Density Weighted Number of Customers (AG)	Substation Capacity (MVA) (AA)	B&V Output Measure (AH)
2008	138,818	9,853	61,439
2009	146,486	9,593	64,350

(Source: FBC Exhibit B-1-1, Appendix D2, Schedule 2 Electric Utility Database)

The trend in B&V's output measure is 1.047 (64,350/61,439). In Table 2.4, the Panel recalculated B&V's output measure using capacity measured in KVA.

Table 2.4 Allette Inc. Output Measure based on Capacity Measured in KVA

Year	Density Weighted Number of Customers (AG)	Substation Capacity (KVA)	Output Measure Using KVA
2008	138,818	9,853,000	5,967,327
2009	146,486	9,593,000	5,869,922

(Output measure calculated by the Panel)

The trend in B&V's output measure is now 0.984 (5,869,922/5,967,327). This illustrates that the trend in B&V's output measure is dependent on the units used for capacity.

Table 2.5 Weighted Output Trend based on Trend in each Output

Year	Customers		Substation Capacity		% Change in Customers	% Change in Capacity	Output Trend
	2008	2009	2008	2009			
Using MVA	138,818	146,486	9,853	9,593	1.055	0.974	1.006
Using KVA	138,818	146,486	9,853,000	9,593,000	1.055	0.974	1.006

(% change in customers, % change in Capacity and Output Trend as calculated by the Panel)

Table 2.5 shows the output trend obtained by calculating the trend in each output measure and then combining those trends with a 60/40 weighting as suggested by PEG. The output trend is the same for both cases and thereby is independent of the units used.

The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend. Although capacity and number of customers are both outputs, they have different units and shouldn't be combined. **Accordingly, the Panel finds that B&V's method of calculating the output trend cannot be relied upon.**

2.2.3.2.3 Input Measures

The inputs to the B&V study consist of a capital cost component and a composite cost component that reflects labour, materials, services and rents. B&V states that both inputs are measured on an ex-post basis using actual financial data for each electric utility and because its input measure is cost based, it does not require an index to convert it to a quantitative base. (FEI Exhibit B-1-1, Appendix D1, p. 10)

However, B&V's methodology does require a cost weighting between the capital and composite cost components. For this purpose, B&V uses the following formula to determine the input cost (Y),[6] on which the year-to-year change in input costs is based:

$$Y = D * (1-J) + (G*J)$$

where D is net plant for gas utilities and net plant less production expenses for electric utilities; G is O&M minus gas costs for gas utilities and O&M minus O&M production expenses for electric utilities; and J is the "Operating Ratio", defined as the ratio of G to operating revenue less gas cost for gas utilities and operating revenue less production expense for electric utilities. (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

B&V calculates the input trend in the same way it calculates the output trend. It uses the above formula to calculate an input cost level for each utility for each year. It then calculates the trend in the input cost level (which it labels "%Δ in Y" in its study). (Fortis, Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base)

CEC explored B&V's methodology, using the example of Alabama Gas from the gas study. The data is reproduced in Table 2.6 for 2007 and 2008.

[6] B&V refer to this as Cost Change. To avoid confusion with the input cost trend, the Panel will refer to this as input cost level.

Table 2.6 Alabama Gas Example

	2007	2008	% Cost Change (2008/2007)
Net Plant (D in the formula above) ($,000)	$660,339	$686,636	3.94%
Operating revenue less gas cost for gas (G in the formula above) ($,000)	$140,186	$139,512	-0.48%
Operating Ratio (J in the formula above)	0.46	0.45	
Input Cost ($,000) Y = D*(1-J)+(G*J)	$498,392	$517,627	
% Cost Change by Year %Δ in Y			3.86%

(Source: Fortis Exhibit B-1-1, Appendix D2, Schedule 2: Natural Gas LDC Data Base; FEI Exhibit B-8, CEC 1.81.22)

For this example, the TFP input cost growth, as calculated by B&V is 3.86 percent. However, CEC point out that net plant grows by 3.94 percent (686,366 /660,339 - 1) and O&M by -0.48 percent (139,512/140,186 - 1) Further, the operating ratio suggests that the 2008 cost weights are 45 percent O&M (55 percent capital).

Accordingly, CEC asked Fortis why it is reasonable that the growth in the combined measure is nearly identical to the growth in net plant and not closer to 1.95 percent, which would be obtained by taking a weighted average of the growth rates. (FEI Exhibit B-8, CEC 1.81.22)

Fortis responds that:

> "[t]he calculation of the input change is not an index. The change is based on the quantity of capital as measured by net plant times the price of capital as reflected in the proxy for capital cost applied to net plant. Similarly for O&M the quantity is measured by the dollars multiplied by the composite proxy price as measured by the percent that O&M represents of revenue. It is easy to see that capital has a larger impact on productivity than does O&M ($26 million compared to $700,000). Simply put, the small savings in O&M translates into a cost impact of less than one million dollars while capital costs increase over six times as

> much. By using the weighted average of the two percentage changes, the estimate of TFP would not reflect the relative importance of each component of productivity." (FEI Exhibit B-8, CEC 1.81.22)

PEG is critical of this approach, stating that "the growth of a proper cost trend index is a cost-share weighted average of the *growth* in the component costs. This finesses the problem of cost sub-indexes with different numeraires that make them impossible to meaningfully add up. B&V instead compute cost *level* indexes and then calculate the growth rates in these indexes." PEG points out that in B&V's approach, the trend in net plant value improperly dominates these calculations because net plant value is not a measure of annual cost like the O&M expenses that B&V uses. (FEI Exhibit C1-9, p. 60)

B&V states that there is no problem "with using cost level indexes with numeraries that differ from utility to utility." It further states that:

> "[e]ssentially, this is a concern only because the index method produces dimensionless measures of inputs and outputs so firms can be collected in the index. Since the B&V method treats each utility as its own entity because each utility has its own production technology set and its own input mix for all inputs this criticism is incorrect. This criticism would be correct for an index type measure because indexes use a dimensionless number that is calculated as the cost divided by a price index and is not really an actual measure of the input which has physical dimension such as miles of pipe or electric circuits." (Fortis Exhibit B-45, p.69)

PEG calculates that using proper output and cost trend indexes and using B&V's sub-indexes raises the MFP estimate by the amount of 0.65 percent for gas utilities and 0.27 percent for electric utilities (FEI Exhibit C1-9, pp. 62, 65).

Commission Determination

The Panel has previously found that it is not appropriate to calculate the output trend using an output level index. Instead, a correct approach is to calculate the trend in each output and then combining those trends using an appropriate weighting. The same principle applies to the calculation of the input trend.

B&V's input measure combines operating costs, which are an annual measure, with net plant which is a point in time measure. Thus, B&V combines $ (net plant) with $ per year (operating costs). This is similar to combining different output measures as previously discussed. CEC calculates an input trend of 1.95 percent, as opposed to the growth rate of 3.86 percent of the input level index, when combining the two inputs with the weighting suggested by B&V. The Panel has no reason to dispute this assertion and notes that an overstated input trend will, all else equal, tend to understate the TFP trend. **Accordingly, the Panel finds that B&V's method of calculating the input trend cannot be relied upon.**

2.2.3.2.4 Inflation in Input Costs

PEG is critical of the tendency of B&V's cost index to overstate costs, stating that using a cost trend unadjusted for inflation materially biases the productivity trend (Exhibit C1-9, p. 58).

In its view, when the Kahn estimate of X is used to estimate the MFP trend and GDPPI is used as the inflation differential, the Kahn estimate is biased by the MFP trend of the economy less the input price differential. PEG states that "[a] Kahn method using US data might nonetheless be used to calibrate the X-Factor of a Canadian PBR plan were the input price differentials and the MFP trends similar in the United States and Canada. However, there is no reason to believe that they are" (Exhibit C1-9, p. 73).

PEG asserts that the input price inflation of energy distributors averaged more than 300 basis points annually in the United States during the years of the study, which materially biases B&V's productivity trend estimate. It considers this a very large error, which "by itself goes a long ways towards explaining the unusually negative trends produced by B&V." PEG calculates an upward adjustment of 3.22 percent to the TFP of gas utilities and 3.35 percent to the TFP of electric utilities to account for this (FEI Exhibit C1-9, pp. 58–59).

B&V argues that, with respect to capital, there is no material bias in its estimate of TFP because it uses net plant to measure capital inputs which is a conservative factor compared to gross plant adjusted for inflation. Regarding the quantum of PEG's proposed adjustment, B&V believes that "given the length of the period any impact or bias would be relatively minor and certainly not the three percent mentioned in the PEG report simply because the net plant measure is far below the gross plant reduced by three percent per year." (Fortis B-45,Rebuttal Evidence, p. 68)

Commission Determination

The Commission Panel agrees with PEG concerning the tendency for B&V's cost based input to understate TFP in the event that inflation in the study dataset is greater than the inflation faced by Fortis. B&V doesn't disagree. B&V also doesn't disagree when PEG states that "input price inflation of energy distributors averaged more than 300 basis points annually in the United States." B&V does argue that, with respect to capital, the effect is not material, because of the way it measures capital inputs. The Panel disagrees. With regard to B&V's argument that the input is less because net plant is below gross plant, the Panel notes that a measurement of net plant value is a cost based measurement that reflects the cost of plant additions.

Accordingly, the Panel finds that B&V's cost based input methodology understates the TFP trend.

2.2.3.2.5 Study Period

CEC states that:

> "[i]n choosing a sample period for an indexing study used in X-Factor calibration, it is generally desirable that the period include the latest year for which all of the requisite data are available. In the present case this year is 2011. It is also desirable for the sample period to reflect the long-run productivity trend. We generally desire a sample period of at least 10 years to fulfill this goal. A long sample period, however, may not be indicative of the latest technology trend. Moreover, the accuracy of the measured capital quantity trend is

> enhanced by having a start date for the indexing period that is several years after the first year that good capital cost data are available. It should also be noted that 2011 was a year of recovery in the United States from the severe recession of 2008- 09." (FEI Exhibit C1-9, pp. 24, 35)

PEG also states that:

> "productivity research for X-Factor calibration commonly focuses on discerning the current *long-run* productivity trend. This is the trend in productivity that is unaffected by short-term fluctuations in outputs and/or inputs. The long run productivity trend is faster than the trend during a short-lived surge in input growth or lull in output growth but slower than the trend during a short-lived lull in input growth or surge in output growth." (FEI Exhibit C1-9, p. 15)

In B&V's view, a shorter period is representative of the types of efficiency gains that might be reasonably expected during a five year plan. B&V submits that PEG's

> " concern about the recession's impact is totally misplaced simply because utility management has the responsibility to manage earnings to market expectations regardless of the macroeconomic circumstances. It would be reasonable to assume that if there was any impact of the recession and inflation during this period, utilities would have attempted to seize every efficiency opportunity that would be accretive to earnings." (Exhibit B-45, Rebuttal Evidence to CEC, p. 68)

B&V states that "the shorter period also avoids a number of practical issues such as the impact of restructuring costs that are not properly included in a TFP study since the costs are not included in rates" (Exhibit B-45, Rebuttal Evidence to CEC, p. 69).

B&V also states that there are a number of long-term trends in new technologies that are fully reflected in the TFP trends in the analysis. These include such trends as "directional drilling, live main insertions, joint trenching and so forth all of which represent mature technologies that are incorporated in the TFP results." However, in its view, using a longer period for an indexing study cannot produce a reasonable expected TFP for a short period simply because the longer period is biased by technology and scale impacts that cannot be replicated in the near term. (Fortis Exhibit B2-11, CEC 3.61.1; Fortis Exhibit B2-10, BCUC 3.23.19.2)

B&V also states that

> "[i]t is also important to note that because the customer and capacity measures of output do not suffer from volatility caused by weather or by the business cycle directly, there is much less need for using long historical periods to estimate TFP for use with a much shorter regulatory control period. Using a long period for estimating TFP may include changes in technology that cannot be replicated during the regulatory control period." (FEI Exhibit B-1-1, Appendix D2, p. 10)

In PEG's view, whether or not the output index is cost based and excludes volatile usage variables, the sample period matters when using Kahn's method because an inflation differential is implicit in the calculation and this can be volatile. PEG states that "[it] is notable that in 1993 Dr. Kahn used the longest sample period that available data permitted at the time." (FEI Exhibit C1-9, CEC Evidence, p. 56)

Commission Determination

The Panel agrees with B&V that if there is evidence of an anomalous productivity trend during the study period that is not likely to continue beyond the study period, it may be appropriate to make an allowance. However, B&V has provided no such evidence of any such trend in the period of 1999 to 2011.

With regard to matching the study period to the PBR Plan length, the Panel agrees that a short-term study may be representative of the efficiencies in a five year PBR plan. However, in order for this to be the case, the five-year study period should be in a similar place in the economic cycle that the PBR period will be in in order for the study period to be representative of the PBR period. Since, by definition it is impossible to accurately predict the future, there is no way to ensure that one can pick the appropriate five-year study window to match the economic conditions that a utility will face in the next five years. **The Panel finds that a short study period is not appropriate.**

A long-term study period is superior to a short-term study period because a long term doesn't accentuate any short-term trends. **Accordingly, the Panel finds that a study period should at least**

be long enough to smooth out any significant short-term economic trends. In this regard, because the four-year period of the B&V study covered the most severe recession in almost 70 years, the results may be prone to a significant bias.

However, there is no direct evidence of what this bias is. Turning to the PEG studies, the Panel notes that in addition to the 1999-2011 study for gas utilities and the 2002–2011 study for electricity utilities, PEG also conducted studies using a subset of its data, from 2008–2011, which provide results for the same period as the B&V study. MFP trend results from PEG's 2008–2011 studies are compared to PEG's longer-term study results in Table 2.7.

Table 2.7 Comparative MFP Results for Different Study Periods

	1999–2011 gas; 2001–2011 electric	**2008–2011**
Gas Utilities	0.96%	-0.07%
Electric Utilities	0.93%	0.90%

(Source: Exhibit C1-9, pp. 24, 35)

Looking only at the difference between the results of the two study periods, the Panel considers this a directional indicator that the result of the shorter study period used by B&V tends to produce a TFP trend that is lower than the longer-term trend. **Accordingly, the Commission Panel finds that B&V's TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.**

The Panel notes that this finding that a longer study period is more appropriate is consistent with the finding of the AUC that "using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation." We note also that the two studies conducted by the OEB were eight and seven years. (Fortis Exhibit B-1-1, Appendix D8, p. 67; Fortis Exhibit B-1-1, Appendix D2, p. 14)

2.2.3.2.6 Use of Logarithmic Growth Rates vs Arithmetic Growth Rates

PEG submits that B&V calculates the average annual growth rates in its cost and output indexes by averaging their *arithmetic* growth rates. In its view, this is well known to be an inaccurate method and PEG considers it more accurate to take the average of logarithmic growth rates. Using B&V's composite output measure, PEG calculates that this raises the average annual growth in the MFP estimate by 0.88 percent for the gas study and 0.27 percent for the electric study. (FEI Exhibit C1-9, p. 62)

B&V states that using logarithms in an academic setting would not create an issue whereas many of the participants in a rate case are not trained economists and may be uncomfortable in the rigorous academic environment. It submits that it is important to communicate with all of the parties in a case and since there is no inherent need to use more complicated formulas, its approach seemed to be reasonable and has a basis in historic calculations of index values. It also states that there was no claim that the results were expected to be accurate to three or four decimal places. (Exhibit B-45, p. 69)

Commission Determination

The Commission Panel accepts PEG's evidence that using arithmetic growth rates is an inaccurate methodology noting that B&V does not dispute this. Further, there is no reason to dispute the quantum of the correction proposed by PEG.

We generally agree with the position of B&V regarding the need to communicate with all parties. However, this is not an issue of the third or fourth decimal place. **Given the materiality of this issue, the Panel finds that B&V's use of arithmetic growth rates results in a substantial understatement of the TFP trend.**

2.2.3.2.7 Summary of B&V Studies

Fortis submits that Dr. Overcast's methodology "is rooted in a practical understanding of how utilities operate. Dr. Overcast's methodology yielded results that make more intuitive sense given that the North American utility industry is characterized by mature utilities with significant capital requirements for system replacement." However, it "is not suggesting that Dr. Overcast's approach yields perfect results." (Fortis PBR Reply, p. 76)

Fortis also states that "[t]he Commission does not need to condemn the expertise or the work product of either Dr. Lowry or Dr. Overcast to determine this case." (Fortis PBR Reply, pp. 75–76)

CEC submits that the B&V productivity results are in fact theoretically unsound and produce results that are inconsistent with the logical foundations of TFP analysis, stating that "the failings of the B&V study be acknowledged and that the study be explicitly assigned no weight in the Commission's deliberations." (FEI Exhibit C1-9, p. 23)

CEC further submits that "[t]he B&V study has numerous flaws that reduce its relevance in this proceeding to the vanishing point" (Exhibit C1-9, p. 58). However, it also states that "the corrected results are consistent with its own estimate of *long* run productivity trends" (Exhibit C1-9, pp. 85–86).

Commission Determination

The Panel has a number of concerns about the B&V studies and is not persuaded that the TFP trend results reported by B&V can be used as a basis to establish an X-Factor.

Dr. Overcast employs a study methodology that is, by his own admission, non-standard. There is no evidence that this methodology has been accepted in any other proceeding. Further, Dr. Overcast has not previously conducted a TFP trend study.

The Panel previously found B&V's use of output and input level indexes inappropriate and cannot be relied upon to generate meaningful input and output trends. We have also made determinations in the areas of input cost inflation, the use of arithmetic vs logarithmic measures and the study length. In all cases, we found flaws in the study methodology that tend to understate TFP trends.

Given the number of shortcomings in B&V's methodology and the errors that arise from these shortcomings, the Panel does not accept B&V's study results.

The Panel notes that there was also considerable argument concerning the following aspects of B&V's input assumptions concerning the input measure:

1. The use of net plant vs. return on net plant; and
2. The omission of depreciation expense from the input measure.

Having not accepted the B&V's study results, the Commission Panel will not consider these issues further.

2.2.3.3 The PEG Studies

2.2.3.3.1 Introduction

PEG's gas distribution MFP trend study, prepared for CEC, is based on data for 64 utilities, including "most of the larger distributors in the United States." PEG states that "[s]ome of the sampled distributors also provide gas transmission and/or storage services but all were involved more extensively in gas distribution." (FEI Exhibit C1-9, p. 21)

For the electric utility study, PEG states that "[t]o be included in the study the data were required, additionally, to be of good quality and plausible. Data from 75 companies met these additional standards and were used in our indexing work" (FEI Exhibit C1-9, p. 31).

PEG describes the I-X formula as an Attrition Relief Mechanism (ARM), differentiating between a single ARM, where all spending, capital and O&M is driven by a single formula, and a double ARM, where capital spending is driven by a separate formula than the O&M spending formula. (Exhibit C1-9, pp. 3–5) PEG's study results are shown in Table 2.8.

Table 2.8 MFP Trend Results for PEG Studies

Gas			Electric		
O&M	**Capital**	**Single ARM**	**O&M**	**Capital**	**Single ARM**
0.98%	2.15%	0.96%	1.51%	0.86%	0.93%

(Source: FEI Exhibit C1-22, BCUC 2.4.1; FBC Exhibit C6-21, BCUC 2.4.1. Based on X-Factor recommendations in the Exhibits indicated less the 0.2 included Stretch Factor)

B&V submits that the PEG studies rely on an academic paradigm or academic model and that "[i]n the academic model it is possible to assume away many of the intricacies of actual process. When those assumptions stray as far away from actual facts as in the case of the PEG method the only alternative is to reject the results and give no weight to the estimates of TFP." (Exhibit B-45, pp. 3, 33)

In B&V's view, the academic paradigm cannot be used in a regulatory proceeding. However, B&V is unable to explain why the academic paradigm is prevalent in regulatory proceedings, stating that "[i]t is difficult to explain why the process of estimating TFP in a regulatory setting has not raised these issues in detail (at least in the United States and Canada) previously. In part, it may be that almost all of the work related to estimating TFP has been performed in the academic paradigm without a critical and detailed examination of the issues related to the economics of actual utility operations." (Exhibit B-45, p. 32)

In addition to criticizing PEG for its use of the academic model, B&V also criticizes PEG because it has not provided the "most up-to-date analysis of the academic paradigm," citing the following elements that are not included in the PEG model:

1. The impact of sunk costs on the development of the appropriate TFP values for gas and electric utilities; and
2. Both billed and unbilled outputs in the measure of the output component of the TFP analysis. The principal unbilled output discussed in the literature is a measure of the capacity component of output.

(Exhibit B-45, pp. 20–21)

Commission Discussion

The Panel is not persuaded by Dr. Overcast's argument to reject the academic paradigm and notes that he rejects only some elements while actually arguing for the inclusion of certain elements of the academic paradigm that Dr. Lowry had not included.

We do not consider it necessary to make a determination concerning which elements of the academic paradigm may or may not be theoretically valid. However, the Panel will consider cases where B&V provides evidence that a specific assumption underlying PEG's study, either flowing from the academic paradigm or any other source, is incorrect and it can show that it has a material impact on the results.

2.2.3.3.2 Output Measures

Table 2.9 shows the output measures used by PEG in its study.

Table 2.9 PEG Output Measures

Electric	**Gas**
number of customers served	number of customers served

Dr. Lowry states that:

> "[t]he number of customers served is a good measure of the number of services, which is a legitimate measure of system capacity. The number of customers typically has the highest explanatory power of the scale variables considered in econometric models of distribution cost…. The number of customers served is correlated with peak delivery capacity because it is dominated by the trend in the number of residential and commercial customers. These customers typically have low load factors." (Exhibit C12-4, p. 5)

Fortis submits that "[b]y choosing to use only one measure of output — net customer growth, Dr. Lowry has an incomplete specification of the output measure and ignores the substantial differences in customer mix that create different output mixes and input mixes to serve customers in different utilities." (FEI Exhibit B-45, p. 4)

Fortis further submits that outputs will be understated (and TFP overstated), by definition, when Dr. Lowry has only accounted for one type of output produced by utilities (customers) and has ignored another (capacity) (Fortis PBR Reply, pp. 68–69).

However, Fortis proposes linking its O&M formula spending to only the number of customers. In that context, B&V believes it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because "[t]he capacity component is not easily measured and would lack transparency if that measure were used. As a result, B&V believes it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula." B&V also states that "there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system." (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, pp. 53, 56)

Commission Discussion

The Commission Panel is not persuaded that PEG's output measure is incomplete or understates the output trend. There is no evidence that this is the case. Further, the Panel notes that, with the exception of FEI's growth capital formula, which uses service line additions, the growth term proposed by Fortis for its PBR formulas uses only customer count. B&V fully endorses that approach, in spite of its position that capacity is a key determinant of utility costs and that it used capacity as an output measure in both of its studies.

2.2.3.3.3 Input Measures

Table 2.10 shows the inputs for the PEG studies.

Table 2.10 PEG Study Inputs

Electric		Gas	
Input Quantity	**Input Price**	**Input Quantity**	**Input Price**
A weighted average of the growth in quantity sub-indexes for labor, materials and services, power distribution plant, and general plant	A weighted average of the growth in price sub-indexes for these same input groups	The difference between the growth rates of applicable O&M expenses and a two-category O&M price trend index	A weighted average of the growth rates in price sub-indexes for capital and O&M inputs. The weights were based on the shares of these input classes in each company's applicable gas distributor cost.

(Source: FEI Exhibit C1-9, pp. 23, 34)

B&V disputes the assumptions used to calculate the sub-indexes in the PEG Report. In its view, this is one of the shortcomings of the academic model. It states that the assumptions required to calculate the inputs are not valid because they rely on the ability to use a single factor (adjusted for regional differences) to convert historic book costs from nominal dollars to real dollars (the deflator) and then rely on a single price index (adjusted only for regional differences in the case of labour) to calculate a measure of inputs (the input quantity). It submits that if either the deflator or the input price is incorrect the results of the PEG method are meaningless and both are incorrect in the PEG analysis. (Exhibit B-45 p. 4)

PEG countered that its indexes are chain weighted, cost weighted indexes and it was only in the sub-indexes that apply to the individual categories that fixed weights are used. (T7:1397)

PEG states that it used input price indexes only to calculate the trends in the quantity sub indexes for major input categories such as capital and labour.

> "Considerable care was taken in choosing the price subindexes. All of the price subindexes were specific to the utility industry and all but those for Material and Services (M&S) expenses reflect regional trends. Although the labor price index pertains to multiple utility industries (including, for example, water utilities), the capital and M&S price indexes for gas utilities are specific to that industry and the capital and M&S price indexes for electric utilities are specific to that industry. The labor price index is specific to salaries and wages because pensions and other benefits are excluded from the analysis." (Exhibit C12-4, p. 4)

PEG further states that it:

> "calculated the productivity growth trends of individual utilities and then took their average. The growth in the summary input quantity index for each utility was a cost-weighted average of the estimated growth in the quantity subindexes for that utility. Time-varying and utility-specific cost share weights were used in these calculations where practicable. For example, the summary input quantity index for power distribution has separate subindexes and company-specific cost shares for distribution capital, general capital, labor, and materials and services." (Exhibit C12-4, p. 4)

B&V submits that, in contrast, its approach is much simpler.

> "It does not require the creation of an index for all companies because it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs. The B&V approach assumes that each company is unique and that it is possible to estimate TFP for that unique mix of inputs and outputs by using only each utility as a separate entity and

> then find a measure of central tendency to estimate the industry TFP." (Fortis Rebuttal Evidence, p. 4)

However, the B&V study methodology considered only price inputs and did not need to convert prices to units of input, so did not actually employ the direct method. PEG does not disagree with B&V, but states that its

> "approach to input quantity measurement is more the rule than the exception in productivity research. Even though the input price indexes employed in such research are not a perfect match for the costs they deflate, productivity indexes are widely used in PBR and in macroeconomic research by government agencies such as Statistics Canada. One reason is that the average inflation in the prices of the true basket of goods and services will usually not differ markedly from the inflation in a basket that is more practical to calculate." (Exhibit C12-4, p. 3)

PEG acknowledges that "[i]n the measurement of utility input trends the accuracy of the indirect approach is greater to the extent that the inflation indexes employed track trends in utility prices and use cost shares that evolve over time (so that the index is chain-weighted) and match those of the utility." (Exhibit C12-4, p. 4)

Commission Determination

The Commission Panel is not persuaded that the use of an input cost index in the estimation of TFP trends "cannot produce a meaningful and logical measure of expected TFP for regulated monopolies" as claimed by B&V. We accept PEG's explanation that no such assumptions are relied on. Further, utilities compete for inputs in an unregulated marketplace. They are faced with labour and material price inflation. In order to compute an input quantity index, either the actual inflation measure that applies to the company must be used, or assumptions about inflation must be made.

What is at issue is the relative accuracy of those two different approaches — the 'direct' method that utilizes costs faced by individual utilities as opposed to the index method that utilizes costs averaged over the study sample.

Our view is that both methods can provide meaningful results. However, we do acknowledge that the direct method, which is advocated by B&V, is conceptually more straight-forward than the index method employed by PEG. It does not rely on the study author's ability to create indexes that are reflective of the actual prices and price inflation faced by the companies in the study and is accordingly, to the extent that the actual data is available, likely to be more accurate. However, B&V provides no evidence that such information is available and that employing the direct method using that data would be more accurate.

The Commission Panel questions whether it is practical to obtain input indexes that are specific to individual utilities. In this regard, Fortis proposes to use a fixed weight index that is not specific to the utility industry in its PBR formula as opposed to a measure of inflation that reflects its own specific circumstances.

The Panel does not agree with B&V that "it is not possible to create a meaningful index since companies are not comparable in terms of the technology used, the mix of inputs and the mix of outputs." PEG acknowledges that its methodology will typically not match the cost shares of an individual utility. Instead, it purports to use them to calculate the average productivity trends of a large sample of utilities. In his view, inaccuracies in applications to individual utilities due to improper cost shares tend to average out. We have no reason to dispute this assertion and are not persuaded by B&V's argument that "small errors in measurement across utilities add up to large errors in the measurement of TFP." B&V has not provided any evidence that the differences will be material or that any systemic bias results from small errors of measurement.

The Panel finds PEG's approach to using input cost indexes to calculate input quantities is acceptable. However, although PEG states that "considerable care was taken in choosing the price sub-index," further consideration of those sub-indexes is required. Accordingly, in the next section the Panel will consider the labour price index and in the following section, the construction index.

2.2.3.3.3.1 Input Labour Price Index

PEG states that for the electric study, the growth rate of the labour price index was calculated for most years as the growth rate of the national employment cost index (ECI) for the salaries and wages of the utility sector of the US economy plus the difference between the growth rates of multi-sector ECIs for workers in the utility's service territory and in the nation as a whole. The quantity sub-index for other O&M inputs was the ratio of the expenses for these inputs to a materials and services [M&S] price index using price sub-indexes for power distributor M&S inputs obtained from the Global Insight Power Planner service. (Exhibit C1-9, p. 74)

For the gas study, PEG states that "[t]he O&M input price indexes summarized trends in the prices of labor and M&S inputs. Price sub-indexes for the M&S inputs of US gas utilities were obtained from the Global Insight Power Planner service." (Exhibit C1-9, p. 75)

Fortis submits that the index Dr. Lowry used to deflate labour costs reflects a mix of costs that are too high for the utilities in the sample or FortisBC, which results in an input quantity that is too low and a TFP trend that is too high. This causes the industry to appear more productive in its use of labour than it really is. (Fortis PBR Final Argument, pp. 109–110)

In the view of B&V, the reason PEG adopts this approach to measuring labour cost inputs

> "lies directly in the use of the competitive model to develop the theory that underlies the academic paradigm and the absence of any consideration for the fundamental nature of regulated utilities. Since the labor input measure is not valid absent the assumptions that the technology and mix of labor employed are the same there can be no viable TFP estimate. This is not a problem for competitive industries because all firms use the same technologies and mix of labor types. The PEG reliance on the competitive model assumptions to estimate TFP cannot produce a meaningful and logical measure of expected TFP for regulated monopolies even if regulation over time may equate revenue to cost in the accounting sense." (Exhibit B-45, Fortis Rebuttal Evidence to CEC, p. 12)

PEG replies that "no simplistic or idealized assumptions that might sometimes be invoked in simplified competitive market models used by academicians are required for the analysis." (Exhibit C14-4, pp. 1, 3)

PEG also comments that "[t]he imperfections of off-the-shelf labor price indexes haven't prevented Fortis from proposing to use the AWE as an inflation measure in their RCIs. The AWE that Fortis proposes to use is a fixed-weight index and is not specific to the utility industry at all, much less to the energy distribution sector of the utility industry." (Exhibit C14-4, pp. 3–4)

Commission Determination

The Commission Panel has previously found PEG's use of cost indexes to be an appropriate way to calculate an input quantity. Therefore, the Panel considers that using a labour price index to convert a labour cost into a labour quantity is an appropriate way to establish labour input quantities, provided the price index used is appropriate.

We do not accept B&V's criticism that a labour input is not valid because the assumption that all firms use the same labour mix is only valid in a competitive industry. There is sufficient similarity among distribution gas or electricity utilities to make such an assumption. **In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.** We note that B&V had no need to make such an assumption as it only used cost inputs.

With regard to Fortis' contention that the labour price index that PEG used reflects a mix of costs that are too high for the utilities in the sample, Fortis provides no evidence to persuade the Panel that this is the case. **The Panel finds that no adjustment to PEG's study results are necessary to account for any potential bias introduced by its labour input index assumptions.**

2.2.3.3.3.2 Input Construction Index

The PEG study utilized the Handy Whitman fixed weight construction index to determine the input capital quantity trend. Fortis relied on confidential Exhibit B2-31 Gas Cost Utility Cost Trend Tables (Handy Whitman Indexes) to compare the Handy Whitman Indices for Steel and Plastic Main for the period 1998 to 2001. The index for steel main has a significant increase, while plastic pipe increased to a lesser degree. Thus, the increase in the cost index for steel main is roughly twice that for plastic main. (Exhibit B-45, p. 26)

However, Fortis states that in 1973, 92 percent of the mains installed were steel and 8 percent plastic, but that by 2011, the ratio had changed to 85 percent plastic and 15 percent steel (T7:1521). Given that the relative weighting of the sub-indices are based on 1973 values, Dr. Lowry agrees that using the total plant index assumes that a “fairly large” proportion of the total plant consists of steel mains (T7:1432–1521).

Fortis argues that “Dr. Lowry’s selection of a fixed-weight index with a distant base year is at odds with the views of Coelli et al who emphasize that indexes used in the context of productivity studies should be chain-weighted (not fixed) so that the weights in the ‘basket’ change to keep pace with developments over time” (Fortis PBR Final Argument, p. 29).

Fortis submits that a construction price index that treats utilities as if they still mostly install expensive steel pipe or copper conductor as had been the case 41 years ago will overstate the real price of inputs and overstate Dr. Lowry’s TFP. In its view, this issue alone resulted in Dr. Lowry’s calculated TFP being overstated by orders of magnitude. (Fortis PBR Reply, p. 68)

Elsewhere in its reply submission, Fortis states that “adjusting Dr. Lowry’s X-Factor for this bias alone would result in a significantly lower X-Factor.” (Fortis PBR Reply, p. 61)

Commission Determination

The Commission Panel agrees that a fixed weight index may not reflect the actual cost of utility plant as well as indexes that are weighted to reflect actual utility plant costs. However, with regard to the specific issue of plastic vs steel pipe that Fortis describes, the Panel is not persuaded that the use of a single plant index results in an overstatement of TFP trend by orders of magnitude.

The Panel accepts that in 2011, 85 percent of installed main was plastic and 15 percent steel represents an industry average. However, there is no direct evidence as to exactly what the percentage of installed mains is steel and what percentage is plastic for the specific utilities in the study period. There is also no evidence of how the steel and plastic mix applies to different diameter pipe. Therefore, it is not possible to determine what adjustment, if any is required. However, the Panel agrees that given the rise in the proportion of plastic main generally and the difference in the price increase for plastic main as opposed to steel main, the fixed weight Handy Whitman Index is likely to overstate the trend in input cost.

For these reasons, the Panel is prepared to consider a modest reduction to the PEG TFP trend result for gas utilities to account for the weighting of construction costs as described by Fortis. **The Panel using its best judgement finds a reduction of 0.06 percent to the MFP trend results from PEG's gas utility productivity study to be appropriate.**

There is no evidence on the record concerning copper conductors. Therefore the Panel will not consider this issue any further with respect to PEG's electric utility study.

2.2.3.3.4 Measurement of Capital Cost

PEG states that its approach to the measurement of capital cost "permits its decomposition into price and quantity indexes". It states that it used for this purpose a COS approach to simulate the approach to capital cost measurement in North American utility regulation. This approach assumes straight line depreciation and a book valuation of capital. The trend in the rate of return is a weighted average of the trends in the regulated returns on equity and the embedded cost of debt. (FEI Exhibit C1-9, pp. 18–19)

Fortis submits that the service value of utility plant does not decline steadily, as Dr. Lowry's approach assumes. "TFP will be too high, by definition, if plant that still has full service value is being treated as if it is not required to generate outputs." In its view, this is a key instance where Dr. Overcast has identified upward bias in Dr. Lowry's calculations and it is a matter of "objective fact, not a difference of expert opinion." (Fortis PBR Reply, pp. 68–69)

To illustrate this point, Dr. Overcast testified that "a third of all the main in the ground is over 41 years old, is still in full service and provides full service value, even though it's fully depreciated." (T6:292)

B&V also cites testimony before the Commerce Commission (New Zealand) in 2009 which concluded: "although it is critical – given the characteristics of energy network assets – to use a service potential profile that reflects one-hoss shay[7] deterioration in measuring the *capital input quantity* [the capital cost charges can be based on a range of forms of depreciation provided they satisfy the condition of ex ante FCM. To ensure consistency with regulatory reporting we use return of capital based on straight–line depreciation]." (Exhibit B-45, p. 27, remainder of quote added from original)

Dr. Lowry states that it is controversial to use an approach to capital that doesn't involve gradual depreciation and notes that the gradual depreciation approach is used in "innumerable studies by federal statistical agencies like Statistics Canada in studies of the MFP trends of the economy." (T6:1333)

[7] 1HS refers to a "One Hoss Shay", which in this context describes a capital asset that exhibits neither input decay or output decay during its lifetime.

He also testified that "studies have shown that when you have a mix of assets of different ages, that as each of them goes *kaput*, they don't all go *kaput* at once. They go *kaput* all the time. And actually that is [a] surprisingly similar quantity trajectory to what you would get with a gradual depreciation scenario" (T6:1332).

Dr. Lowry also stated that in his view, the 1HS methodology does not necessarily reflect the cost of replacement capital. He testified:

> "…because you are replacing the old input, and so that's falling off as you add the new one. It's only under cost of service regulation that that would necessarily result in a bump in your quantity. That's the approach that Black and Veatch has disputed. But I think, as I've mentioned, … they kind of go back and forth between the cost of service paradigm in which, thanks to gradual depreciation you do get a bump in capital quantity with replacement, but with the more one-hoss shay approach, you wouldn't necessarily because you are replacing an asset that supposedly until that time was perfectly serviceable." (T7:1359–1360)

In PEG's view "it is not clear that a correctly implemented IHS approach to capital costing would produce MFP trends markedly different from those that I report in [Dr. Lowry's] testimony. Dr. Makholm has used this approach in research and testimony once in Maine and twice in Alberta. The estimated MFP trends he reported in these three studies were 0.44%, 0.78%, and 0.96% respectively." (Exhibit C12-4, p. 3)

Dr. Overcast disagrees, stating that "the basis for that conclusion can't possibly be correct" because the PEG method excludes the 33 percent of all gas main in the US, from their measure of inputs. He bases this estimate on the Pipeline and Hazardous Safety Material Administration's database, which reports the age of these assets. (T1:1509)

However, Dr. Overcast does not suggest a specific adjustment to PEG's TFP trend results to account for the difference between the two methodologies. Further, B&V states that in its study, it used the change in net plant (gross plant additions less annual depreciation expense) and did not adjust this value for inflation. (Exhibit B-45, p. 27)

Commission Determination

The Panel is not persuaded that the results of the PEG study should be adjusted to account for any potential upward bias that may be attributable to the assumption of gradual depreciation in the capital costing approach. Although assuming gradual depreciation may bias the results upward, there may also be an offsetting effect because of the increased maintenance costs associated with aging capital. Further, B&V provides no quantitative analysis of any potential bias and Dr. Lowry states that "it is not clear that including costing would produce MFP trends markedly different" from those reported in the PEG study. The Panel finds no reason to disagree.

The One-Hoss Shay methodology is an element of the academic paradigm that Dr. Overcast is critical of Dr. Lowry for not including. However, the Panel accepts Dr. Lowry's evidence that this element is controversial, and notes that B&V also appears not to take this approach in its study assumptions.

Accordingly, the Panel finds that no adjustments are necessary to account for PEG's capital costing approach.

2.2.3.3.5 Negative Salvage

Fortis submits that capital inputs will be understated (and Dr. Lowry's TFP trend results overstated), "by definition, if there is no recognition given to the material net cost of decommissioning plant (net negative salvage)." (Fortis PBR Reply, pp. 68–69)

Dr. Lowry states this is a reasonable simplification given its small importance (FBC Exhibit C6-15, IR 1.3.11).

Commission Determination

B&V provides no quantification of the impact of not including negative salvage, and there is no evidence that indicates that the inclusion of negative salvage will have a material impact on the results of Dr. Lowry's studies. In the absence of any evidence to the contrary, the Panel accepts Dr. Lowry's assertion that "this is a reasonable simplification given its small importance." **Accordingly the Panel declines to make any adjustments to the study results to account for negative salvage.**

2.2.3.3.6 Input Inflation vs. Output Inflation

Fortis submits that the PEG results are overstated because PEG has not "calibrated" its calculations. Fortis further submits that Dr. Lowry clearly indicates in his evidence that "…when a macroeconomic inflation measure is used, the ARM must be calibrated in a special way if it is to reflect industry cost trends." It also states that:

> "[u]sing an output-based inflation index is problematic because the measure of output inflation already incorporates the effects of economy-wide productivity gains. In other words, BC-GDPIPIFDD already incorporates the effects of the BC economy-wide productivity gains and therefore would not necessarily be indicative of the input price inflation likely to be experienced by the Companies during the plan term. For this reason, the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input."

In Fortis' view, PEG ignores this integral component of its own theory and does not calibrate its X-Factor range recommendations "despite recommending that the Companies use the macroeconomic indicator BC-GDPIPIFDD for its I-Factor" (Fortis PBR Reply, pp. 70–71).

The adjustment suggested by B&V is based on a calculation of growth in revenue per customer provided by PEG (as equation 16 in its filed evidence):

$$growth\ Revenue/Customer = growth\ GDPPI - \left[\begin{array}{l}\left(trend\ MFP^{Industry} - trend\ MFP^{Economy}\right) \\ + \left(trend\ Input\ Prices^{Economy} - trend\ Input\ Prices^{Industry}\right) + Stretch\end{array}\right]$$

B&V states that "The term in brackets must be calculated to produce the appropriate X-Factor under the PEG methodology." (Exhibit B-45, p. 60)

Using as an example the X-Factor for capital for gas distribution utilities, B&V calculates the term in brackets as follows:

$$\begin{aligned}\mathbf{GrRevPerCust} \\ &= \mathbf{BC - GDPPIFDD_{Growth}} - [(\mathbf{1.34}_{\textit{trend MFP Ind.}} - (\mathbf{-0.45}_{\textit{trend MFP Econ}})) \\ &\qquad + (\mathbf{1.31}_{\textit{trend IP Econ}} - \mathbf{3.16}_{\textit{trend IP Ind.}}) + (\mathbf{0.20}_{\textit{Stretch Factor}})] \\ &= \mathbf{BC - GDPPIFDD_{Growth}} - [\mathbf{0.14}_{\textbf{Calibrated X-Factor}}]\end{aligned}$$

B&V used the following factors in the equation above:

Table 2.11 Adjustment Inputs

Adjustment Inputs

	Economy	Industry	Stretch Factor
Trend MFP	– 0.45%[31]	1.34%[32]	0.20%[33]
Growth BC-GDPIPI^{FDD}	1.76%[34]		
Trend Input Price	1.31%[35]	3.16%[36]	

31 PEG Evidence Exhibit FEI C1-9 and FBC C6-9, p.14,
32 Recommended X derived from Response to BCUC IR1.22.1, Attachment BCUC-CEC (1) 10.3
33 Ibid. p.70
34 BC-GDPIPI^{FDD} (2003 to 2012) from Table 7, Section 5 PEG Evidence
35 Calculated as MFP Trend Economy + Growth BC-GDPIPI^{FDD}; Deduced from Dr. Lowry's formula [15]
36 Input Price Trend of U.S. Gas Distributors (1999-2011) from Table 3, Section 3 PEG Evidence

B&V compares the resulting X-Factor to the X-Factor calculated by PEG and describes the difference as the calibration. The resultant calibrations are 1.03 percent for FEI and 0.92 percent for FBC. (Exhibit B-45, pp. 63–64)

PEG comments that "X will be larger, slowing revenue growth, to the extent that the industry MFP trend exceeds the economy-wide MFP trend embodied in the GDPPI." It asserts that the MFP trend of the US economy is believed to be fairly brisk, with 1.1 percent average growth in the last 10 years. In its view, this warrants a sizable adjustment to the X-Factor in the US when the GDPPI is used as the inflation measure. In contrast, it states that in Canada, however, the analogous MFP index has declined by 0.45 percent annually on average over the last ten years. (FEI Exhibit C1-9, pp. 13–14)

The AUC considered calibration to the TFP trend, in the event that an output-based inflation measure is chosen for the PBR plan. The AUC Panel found that both components of the approved I-Factors (AWE and CPI) can be considered input based price indexes so no further adjustment was required. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 86–87, 92–94)

Commission Determination

The Commission Panel is not persuaded that the adjustment proposed by B&V is required. The Panel accepts that "the theory requires the TFP estimates to be calibrated to produce an appropriate X-factor in order to correct for the difference between output inflation included in the inflation factor and the industry input." The calculation provided above by B&V relies on the assumption that the I-Factor is GDPPI, which is a measure of output inflation. However, the Panel has previously approved the use of the CPI and AWE, which Fortis argues are reflective of the input inflation it faces.

Accordingly, the Panel finds that B&V's proposed calibration is not required.

2.2.3.3.7 Summary of PEG Studies and Comparison to other Studies

2.2.3.3.7.1 The AUC Studies

For its Performance Based Rate Regulation proceeding, the AUC engaged the National Economic Research Associates (NERA) to conduct a TFP trend study applicable to Alberta gas and electric companies. NERA filed its report dated December 30, 2010. The study was based on a population of 72 US electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP trend of the distribution component only of the electric companies. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, p. 59)

In addition to NERA‘s study, PEG on behalf of an intervener, also performed an MFP trend study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companies as providers of gas transmission, storage, distribution, metering and general administration services. (FBC Exhibit B-1-1, Appendix D8, p. 59)

Table 2.12 AUC Hearing TFP Study Results

Jurisdiction	TFP/MFP	Period Covered	Dataset
Alberta—NERA	0.96%	1972–2009	72 U.S. electric and combination electric/gas companies
Alberta—PEG	1.32% – 1.69%	1996–2009	34 U.S. gas distribution companies over the period of 1996 to 2009

(Source: Exhibit B-11, BCUC 1.1.2)

While acknowledging the value of a separate productivity study focusing on gas distributors, the AUC ultimately did not rely on the PEG report on the basis that: 1) the choice of a sample period in

PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria; and 2) PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. Instead, the gas distribution companies that were parties to the proceeding, agreed that NERA's study provided a reasonable starting point for determining the TFP trend for gas distributors." (FBC Exhibit B-1-1, Appendix D8, pp. 86–87)

The issue of the choice of NERA's output index — throughput — was explored in the AUC proceeding. The AUC found that when selecting an output measure, it must be matched to the type of PBR plan. In this case, the AUC accepted the single throughput output index as appropriate as the proposed PBR plans were price-cap plans. (FBC Exhibit B-1-1, Appendix D8, AUC 2008 Decision, pp. 82–83)

B&V is of the view that "a separate measure of TFP should be used for gas and electric utilities just based on fundamental differences in both the cost and output drivers." (Exhibit B-1-1, Appendix D1, p. 34)

B&V is critical of NERA's TFP academic study methodology, because "the real world of utility operation is not the world of the current academic paradigm. In order to become useful for application in utility regulation, academic studies must be modified to adequately model the key drivers of cost and be more comprehensive in scope by including all of the costs associated with delivery service." (Fortis Exhibit B-1-1, Appendix D2, pp. 31–32)

B&V submits that "the AUC Plan and the NERA study on which it was based should not be used as a basis for the development of a PBR Plan for FortisBC" (FBC Exhibit B-1-1, Appendix D2, p. 39).

CEC asserts that the NERA study "was designed to provide a long term analysis with a long term MFP trend and as such remains consistent with other analysis" (CEC PBR Final Argument, p. 47).

Commission Determination

The Commission Panel agrees with B&V that the NERA study results should not be applied to FEI, as the study only considered electric distribution utilities. However, the Panel considers that the NERA study results have relevance in this proceeding and is inclined to assign them some weight with regard to the electric utility productivity trend. In making this determination, the Panel considered the study length, the dataset used for the study and the output measure relative to the PBR plan the study was prepared for. These issues have all been thoroughly canvased in this proceeding.

The TFP of 0.96 percent approved by the AUC is comparable to the results of PEG's gas utility study presented in this Proceeding.

Given that the PEG AUC study was rejected by the AUC, and has not been tested in this proceeding, the Panel will place no weight on it

2.2.3.3.7.2 The OEB Studies

Table 2.13 OEB Approved TFP Trend Results

Jurisdiction	TFP/MFP	Study Date	Period Covered	Dataset
Ontario 3rd Generation	0.72%	2007	1988-2006	US Utilities
Ontario 4th Generation	-0.33%	2013	2002-2012	Ontario Electric Utilities

(Source: FEI Exhibit B-11, BCUC 1.1.2)

Under the third generation PBR, the OEB decided that due to the lack of a comprehensive Canadian (or Ontario) utilities' financial and operational database, the data from US peer group companies may be used to measure TFP. The study utilized U.S. data for the period of 1988–2006 and calculated a productivity factor of 0.72 percent, which was approved by the OEB in September

2008. However, for the fourth Generation PBR the TFP study was based on Ontario data instead of US data. (FBC Exhibit B-1-1, Appendix D2, p. 14)

A report prepared for the OEB by PEG explained that:

> "the 2012 TFP and econometric results were impacted by three issues with the 2012 data: 1) data were not available on embedded distributors' LV payments made to host distributors; 2) at least 13 distributors adopted international financial reporting standards (IFRS) for the first time in 2012; and 3) a number of distributors cleared balance sheet deferral accounts in 2012 and moved the associated costs to their Trial Balance OM&A expense accounts. Of these three data issues, PEG's TFP results were most affected by the clearing of the deferral accounts to expense."[8]

Commission Discussion

There are issues that, in the Commission Panel's view, limit the applicability to this proceeding of both the third and the fourth generation OEB studies.

The fourth generation study is a study of Ontario electrical distribution utilities. There is no evidentiary basis on which to conclude it is applicable to a gas distribution utility, or how the results can be modified to so apply. Accordingly, the Panel will give no weight to this study with regard to the determination of a TFP trend for the gas utilities. For the same reason, the Panel assigns no weight to the third generation study.

With regard to the applicability of the fourth generation study to electric utility MFP trends, the Panel is concerned that the results may be skewed by the three issues outlined in the PEG report, in particular the issue of clearing the deferral accounts. Accordingly, in the absence of further evidence, the Panel is not prepared to give any weight to this study.

8 Empirical Research in Support of Incentive Rate-Setting: 2012 Update, September 2013, by PEG, available in Fortis Exhibit B-27, Witness Aid, Empirical Research in Support of Incentive Rate-Setting: 2012 Update Report to the Ontario Energy Board September 2013, p. 25.

Regarding the applicability of the third generation study to the electric utility MFP trends, the Panel is mindful of the objections of Fortis that the study period is over seven years ago, and will assign no weight to that study.

2.2.3.3.7.3 Summary of PEG's Studies

Fortis submits that "[u]nderstanding what causes a negative TFP value, and its significance, is fundamental to understanding why Dr. Overcast's measured negative TFP values make more sense than Dr. Lowry's large positive values in the present circumstances" (Fortis PBR Final Argument, p. 74).

CEC submits that the Commission has little choice in this debate but to conclude that the PEG research is the superior evidence and methodology by far, not only because of the technical explanations and analysis but because it yields usable results which the B&V evidence clearly does not. (CEC PBR Final Argument, p. 49)

IRG submits that "In this proceeding, the two witnesses clearly disagreed on a surprising number of issues. On balance, the IRG supports the more persuasive evidence of Dr. Lowry." (IRG Final Argument, p. 3)

Commission Determination

The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding. In the Panel's view, with the exception of a small adjustment required to account for the use of the fixed price construction index basket, the underlying assumptions are reasonable and the study length is appropriate. **Accordingly the Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.**

With regard to Fortis' assertion that negative TFP trends make more sense, the Panel is not persuaded that this is the case. B&V asserts that "there's a lot of infrastructure replacement going on," but does not provide any specific evidence of this replacement for the utilities in either its own or PEG's utility datasets over either study period. The Panel has previously found there are a number of methodology issues, including study period, the use of logarithmic vs. arithmetic growth rates and the way input levels are calculated, that can account for the negative TFP found by the B&V studies.

Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.

2.2.3.4 Stretch Factor

2.2.3.4.1 The Proposed Stretch Factors

B&V states that its recommended X-Factor of 0 percent for each utility "is based on several features of the overall plan that we believe reduce the negative TFP closer to zero." B&V does not quantify the various adjustments it made to the TFP trend results, but states that "[t]he 0% X-Factor would include a stretch factor as well." (FEI Exhibit B-11, BCUC 1.44.13)

Fortis proposes an X-Factor of 0.5 percent submitting that this "exceeds Dr. Overcast's measured industry and economy wide productivity levels by a significant margin, and presents a challenge to the Companies to seek additional efficiencies" (Fortis PBR Final Argument, p. 61). B&V regards this additional stretch factor as being more aggressive than is warranted (FEI Exhibit B-1, pp. 43, 48).

FEI states that "[s]tretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective" (FEI Exhibit B-1, p. 42).

FEI also states that:

> "[i]f the Commission determined a more aggressive 'stretch' productivity factor, FEI would reassess its plans on how to proceed but it is difficult to identify any particular

> response in the abstract. FEI would not consider the stretch productivity factor in isolation but rather would base its reassessment on the combined effect of the Commission determinations on all PBR Plan elements to determine whether or not the overall impact allowed the utility an opportunity to earn its fair return consistent with regulatory and legal principles." (FEI Exhibit B-8, CEC 1.4.2)

This issue is pursued at some length by ICG. For example, it submits that:

> "FBC has failed to provide any evidence that is relevant to whether it operates efficiently. In the absence of any relevant evidence, the Panel must assume that factors other than efficiency measures and efficient operations all but ensure higher than approved returns for FBC. Mr. Overcast confirmed that conclusions regarding the efficiency of FBC could not be drawn from either 1) the historic PBR Plans, or 2) TFP analysis. The evidence does not even permit the Panel to conclude that FBC is a high or low cost provider as compared to other utilities in BC. FBC consistently objects to such evidence being filed, and now must accept the consequences of such objections." (ICG Final Argument, p. 4)

Commission Determination

The Commission Panel agrees with ICG that there is a lack of evidence as to the efficiency of Fortis' operations relative to other utilities. This information would be helpful in making a determination on a stretch factor. A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed prior to the application for the next phase of the PBR. **Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.**

In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. As a result of this consultation, the Panel expects that agreement be reach on the broad terms and parameters of the study**. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.**

2.2.3.4.2 PEG's Recommendation

PEG states that

> "both Fortis units have operated under PBR in the past. However, the PBR plans for both companies exempted a large portion of capital cost from the force of PBR, and both companies have now operated for a few years under cost of service regulation. Neither company has presented convincing evidence of superior operating performance in this proceeding. On the basis of the available evidence, it is reasonable to assume that each company is an average cost performer."

Based on this observation and the proposed 50-50 earnings sharing mechanism, PEG recommends a stretch factor of 0.2 percent. (FEI Exhibit C1-9, p. 70)

2.2.3.4.3 Previous Fortis PBR Plans

The parties involved in the NSP for FEI's previous PBR agreed that "linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009." (FEI Exhibit B-1, p. 35)

For FBC, the 2006 Negotiated Settlement Agreement established an X-Factor of 2 percent for 2007, 2 percent for 2008, and 3 percent for 2009 (if the term of the PBR was extended). For the period 2009–2011, the Parties to the 2009 NSA agreed that some linking of the productivity factor to BC CPI would be beneficial. As such, the 2009 NSA established X-Factors of 1.5 percent for 2010 and 2011 when BC CPI is less than 3 percent, with the X-Factor increased to offset any increase in BC CPI above 3 percent. (Fortis Exhibit B-1-1, Appendix D1, p. 25)

FEI submits that:

> "[a] utility's past history with PBR plans may also be considered for X-factor determination. Ordinarily, utilities with no previous experience with PBR plans (as is

the case for Alberta's utilities) may have a better chance to improve performance at a faster rate than the industry average (the inefficient utilities have more —low-hanging fruit or cost savings that can be implemented easily). This may justify a higher than usual X-factor used in Alberta in comparison to a utility like FEI that has years of recent experience with PBR and fewer available productivity improvement opportunities." (FEI Exhibit B-11, BCUC 1.6.1)]

However, Fortis also argues:

- First, neither of the PBR experts in this case, including CEC's own expert, used the previous negotiated X-Factor as the starting point for their recommendations. Rather, Drs. Lowry and Overcast both based their recommendations on industry productivity levels, which is consistent with what is done in other jurisdictions where PBR has not been negotiated. The TFP study undertaken by Dr. Overcast yielded a negative TFP. FBC's prior history under PBR only came into play in determining the stretch factor. Drs. Lowry and Overcast agreed that the stretch factor should decline over time to recognize diminishing returns.
- Second, the fact that the X-Factor averaged 2percent during the last FBC PBR is not a rationale for adopting the same X-Factor today. TFPs have been declining, and accelerated infrastructure replacement continues. PEG recently calculated a negative TFP in Ontario, and even Dr. Lowry's recommendation and NERA's values in Alberta fall well short of the number advocated by ICG. (Fortis PBR Reply, p. 75)

2.2.3.4.4 Stretch Factors from Other Jurisdictions

The AUC approved a stretch factor of 0.2 percent be used by the respective Alberta distribution utilities in their PBR Plans. It was assumed that the transition to PBR from COS regulation would produce immediate expected increases in productivity growth. As such, the purpose for the addition of the 0.2 percent stretch factor was to share between the companies and customers these immediate expected increases in productivity growth. (Exhibit B-1-1, Appendix D2, p. 5)

The OEB

> "concluded that there are considerable variances between existing efficiency cultures of the utilities and that a single stretch factor for all distributors is not appropriate. Therefore, two benchmarking evaluations were considered to divide the Ontario's power distributors to three efficiency 'cohorts' where each cohort was given a specific stretch factor. While grouping of distributors into three cohorts was based on solid benchmarking techniques,

the determination of stretch factors values was mainly subjective and based on the OEB's judgment." (FEI Exhibit B-1-1, Appendix D2, p. 14)

Table 2.14 OEB Stretch Factors

Characteristic	Cohort One	Cohort Two	Cohort Three
Criteria for cohort groups	Statistically superior econometric benchmark and (2) top quartile result in the unit cost index benchmark	Superior in one methodology and inferior in the other one	Inferior in both benchmarking techniques
Stretch factor value	0.2	0.4	0.6

(Source: Exhibit B-1-1, Appendix D-2, p. 14)

Commission Determination

In the absence of a benchmarking study, the Panel considers the following:

1. Fortis' proposed stretch factor of 0.5 percent, which is in addition to the stretch factor embedded in B&V's recommended X-Factor;
2. Dr. Lowry's suggested stretch factor of 0.2 percent; and
3. The range set by the OEB of 0.2 percent to 0.6 percent.

A stretch factor in excess of 0.5 percent is substantial. It is, for example, considerably larger than PEG's proposed stretch factor of 0.2 percent. When compared to stretch factors approved by the OEB, this would put Fortis in the range of the least efficient utilities. This is contrary to FEI's assertion that "FEI has already realized significant efficiencies under its previous PBR that can only be achieved once" and that "efficiencies that can be expected to be achieved under PBR decline over successive PBR terms" (FEI Exhibit B-53, Panel 2.1). Accordingly, the Panel gives no weight to Fortis' proposed stretch factor.

The Panel agrees with Fortis that past history may be considered. However, the Panel also agrees that a utility that has years of recent experience with PBR may have fewer available productivity improvement opportunities. Accordingly, stretch factors from recent previous PBR periods could suggest upper limits to stretch factors going forward.

Upon reviewing Fortis' previous PBR Plans, we note that in all cases except for 2007 to 2009, inclusive, the X-Factor varies, based on forecast CPI. This is a different approach than proposed in this Application, where the X-Factor is fixed, regardless of inflation. The Panel does not find it appropriate to impute a stretch factor under these circumstances. To impute a stretch factor from FBC's negotiated X-Factors of 2 percent for 2007 and 2008, and 3 percent for 2009, the Panel assumes a TFP of 0.93 percent. This results in a stretch factor of a little over one percent for 2007 and 2008, and a little over two percent for 2009. However, given that FBC has been in a PBR regime for a substantial amount of time, it would not be appropriate to continue with the same stretch factor and a reduction is appropriate. Further, considering that FBC has been in a PBR regime longer than FEI, a lower stretch factor for FBC is appropriate.

Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.

2.2.3.5 Setting the X-Factor

As previously set out, in determining the X-Factor, in addition to considering the TFP trend and the stretch factor, the Panel will consider the adjustments that Fortis proposes to account for its specific circumstances and also apply our own judgement to determine if any additional adjustments are required.

2.2.3.5.1 Fortis' Proposed X-Factor

Fortis proposes an X-Factor of 0.5 percent, suggesting that, although it is substantially higher than B&V's recommended X-Factor, it is reasonable. In support of its proposed X-Factor, Fortis cites the following:

a. Accelerated trend in asset replacement in the gas and electric utility industries. This has resulted in a more negative TFP trend than is attributable to Fortis, because Fortis proposes to exclude significant portions of capital from its formula spending.
b. PEG's recommended X-Factors for Ontario utilities is close to zero; and
c. A high-level comparison with illustrative revenue requirements forecasts show that the proposed 0.5 percent X-Factor, along with the proposed composite inflator, will result in rates that are lower than the rates under a cost of service model.

(FEI Exhibit B-1, p. 53; FBC Exhibit B-1, p. 49; Fortis Reply, p. 72)

Fortis also submits that "it can be argued that the X-Factor for a PBR plan with an earnings sharing mechanism is less significant than under a plan with no earning sharing mechanism." (FEI Exhibit B-1, p. 51, FBC Exhibit B-1, p. 47)

ICG submits that "[a]ssuming the Panel approves a PBR Plan, the ICG recommends an X-Factor of 2% to match the average X-Factor during the last PBR Plan" (ICG Final Argument, p. 23).

2.2.3.5.2 Single ARM vs Double ARM

In PEG's view, the single ARM approach has a more solid empirical foundation provided that the capital cost tracker is redesigned along more conventional lines. PEG believes that a single ARM, applicable to most of the companies' revenues, and separate ARMs for capital and operation and maintenance expenses are both potentially workable for the Fortis companies. However, in its view, an issue with the single ARM approach is the unusually large amount of capex that would be separately addressed by a cost tracker. PEG recommends tightening the eligibility standards for the capital cost trackers to mitigate this issue. (FEI Exhibit C1-22, BCUC 2.3; FEI Exhibit C1-22, BCUC 2.4.1)

FEI states that although the costs are looked at separately to allow more appropriate cost drivers to be assessed from each side, its building block model proposes the same X-Factor for each block. It further submits that a single X-Factor is what Dr. Lowry refers to as a single-arm approach, which is the same approach that is taken in "all of the other plans that the Commission has evidence before it on." (T8:1397)

2.2.3.5.3 Adjustments for Excluded Capital

Fortis proposes to exclude all CPCN capital from its formula driven spending envelope. For FEI, this includes all capital over $5 million and for FBC all capital over $20 million and in some cases, capital projects of any size below $20 million. PEG estimates that this amounts to 30 percent of all capital expenditures for FEI and 40 percent for FBC. (FEI Exhibit C1-22, CEC Response to BCUC 2.4.3)

PEG states that there is no established methodology for making such exclusions. However, when asked to provide study results assuming exclusion of similar amounts of capital, it reported an increase in the single arm MFP trend to 1.98 percent. In its view, "[t]his result would be pertinent for the calibration of an X-Factor for a comprehensive revenue cap index, assuming that CPCN costs flow through a tracker." (FEI Exhibit C 1-13-1, CEC Response to BCUC 1.13.3)

2.2.3.5.4 X-Factor Evidence from Other Proceedings

X-Factor evidence was also presented from Alberta and Ontario. In Ontario, X-Factors are either the result of negotiated settlements or are calculated as the sum of the TFP trend and a stretch factor.

Fortis submits that when reviewing the X-Factors in other jurisdictions, the timing of these decisions is important when there is evidence of accelerating asset replacement occurring in the last five years that is expected to continue during the PBR term. Apart from Alberta's X-Factor of

1.16 percent, all of the other cited X-Factors over 1.0 percent were set at least five years ago, presumably based on even older information. (Fortis PBR Reply, p. 72)

With regard to the AUC's X-Factor, Fortis submits that it is based, "by and large, on expert evidence that used the same academic assumptions used by Dr. Lowry that do not properly reflect actual productivity." It further states that "[b]oth experts in this proceeding also considered the NERA analysis relied upon by the AUC to be incorrect." (Fortis PBR Reply, p. 72) However, Dr. Lowry stated that although there were "lots of little technical errors" in the NERA study, he does not suggest that the result is upward-biased (T7:1386–1387).

Commission Determination

The Commission Panel has the following comments concerning the three factors Fortis cites in support of its proposed X-Factor:

a. **Accelerated asset replacement trend**. This issue arises because B&V and Fortis attribute the negative TFP trends from the B&V studies to accelerated asset replacement. The Panel has previously determined that shortcomings in the study methodology may account for the negative TFP trends. Further, the Panel has determined that it will not accept the results of the B&V studies. Accordingly the TFP trend results from these studies cannot be used as a basis for even the hybrid judgement approach. We will not consider the issue of asset replacement any further in making our X-Factor determination.

b. **PEG's Ontario X-Factor Recommendation**. In our review of the OEB proceedings, the Panel found that the principle reason the MFP trend was close to zero was due to the OEB requirement to clear deferral accounts. As such, the OEB result has little relevance in this proceeding. The Panel will not consider this issue any further.

c. **Comparison to COS Rates**. We do not consider an "illustrative revenue requirements forecast" to be a reasonable basis on which to make an X-Factor determination. The "illustrative forecast" has not been adequately tested and, as such, may be prone to error and bias. It cannot be viewed as a cost of service requirement for the next five years.

With regard to Fortis' statement concerning the reduced importance of the X-Factor if the PBR plan includes an earnings sharing mechanism, it is unclear to the Panel how, if at all, this may have influenced either B&V's or Fortis' judgement based adjustments. It is not clear to the Panel what is meant by "reduced importance". It is not appropriate to use the presence of an ESM to justify an X-Factor that may, for example, be too low. In that circumstance, the X-Factor would enable the utility to over recover its costs. While sharing that over-recovery with its customers does mitigate the effect of the over recovery somewhat, it is not sufficient justification to use an X-Factor that is understated.

For all of the above reasons, the Panel is unable to approve the X-Factor as applied for.

The Panel accepts PEG's assertion that the single ARM has a more solid empirical foundation. In addition, the Panel agrees with Fortis that its proposed plan has the characteristics of a single ARM approach. However, the Panel is concerned that because of this proposed treatment of capital expenditures, an adjustment to the single ARM X-Factor may be required.

The Panel is mindful of the comments of both experts regarding excluded capital. We agree that if significant capital spending is excluded from the PBR formula driven spending envelope, adjustments to the formula may be necessary. B&V included this consideration in its upward adjustment of approximately 4 percent but, as discussed previously, does not provide any details concerning that adjustment. Accordingly, it is not possible to discern the directionality of the adjustment to allow for excluded capital, although the magnitude of the gross adjustment suggests that the effect of excluded capital may be to drive the TFP trend upwards. The results reported by PEG are also suggestive that its reported single ARM MFP trend is too low when applied to a PBR plan with a significant amount of excluded capital. **Accordingly, if significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.**

The Panel considers the matter of excluded capital further in Section 2.3.5 of this Decision. There, the Panel finds that the CPCN based exclusion criteria proposed by Fortis is not appropriate and invites further submissions from parties on the issue of the threshold for excluded capital.

Accordingly, the Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.

Having considered FEI's special circumstances and the overall design of the PBR plan, no further adjustments are required at this time.

Accordingly, the Commission Panel has determined the following X-Factors should be applied to Fortis' proposed PBR formulas for the PBR term:

Table 2.15 Approved X-Factors

Utility	TFP	Stretch Factor	X-Factor
FBC	0.93	0.1	1.03
FEI	0.90	0.2	1.10

2.2.4 Exogenous or Z Factors

Fortis proposes that exogenous factors, which it characterizes as "non-controllable and unforeseen costs/revenues," be flowed through to rates during the PBR term (FEI Exhibit B-1, p. 70). The Companies state in their Final Argument that "it is not necessary, and is impractical, to be overly prescriptive in advance as to mechanisms for addressing exogenous factors"; therefore, Fortis submits that it will notify the Commission and stakeholders of exogenous events in a variety of ways, including through the Annual Review process or through a letter to the Commission, depending on the type of exogenous factor event (Fortis PBR Final Argument, p. 48). Fortis states that the recovery of exogenous factor events in rates may be achieved through a variety of mechanisms such as flow-throughs, deferral accounts and true-ups. (Fortis Exhibit B2-11, CEC 3.29.7)

The Companies provide a list of exogenous factors in their Applications. This list serves as an example of types of events that fall under the classification of "exogenous"; however, the

Companies submit that this list is not exhaustive but merely serves as an example of the types of events that would lead them to apply to the Commission for exogenous factor treatment. The exogenous factors listed in the Applications are as follows:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes and changes to cost of capital).

Certain of the above exogenous factors, including catastrophic events, bypass or similar events, and major seismic incidents are further explored in the BCUC IR 3.22 series of questions in Exhibit B2-8 of the Fortis PBR proceedings. For instance, Fortis described a bypass event as a situation where a customer may be physically taking service from another supplier while remaining within the service territory and thus making no use of the Company's facilities, or where it has become economic to leave the Company's service area for another location because of rate or other utility policies that have caused the costs to the customer to exceed its standalone costs. Fortis submitted that a bypass event qualifies as exogenous because, unlike in an unregulated environment, the Company is not free to adjust its prices between its marginal cost and the standalone cost of its customers.

Fortis does not propose to apply any criteria or a materiality threshold to exogenous factor events. Instead, the Companies submit that "[w]hile, in principle, all unforeseen events that are beyond the Companies' control should be treated as exogenous, the Companies' evidence is that they may choose not to apply to recover amounts related to small events that do not have an impact on the Companies' ability to serve its customers and that do not have a material cost impact." (Fortis PBR Final Argument, pp. 47–48)

Fortis' proposed treatment for exogenous factors is consistent with the Companies' approach in previous PBRs; however, it differs from the approach taken by other Canadian jurisdictions under PBR. The other jurisdictions take a more prescriptive approach to the definition of exogenous factors through the establishment of a set of applicability criteria and a materiality threshold. This provides for greater clarity when determining if an event is eligible for exogenous factor treatment. (Fortis Exhibit B2-11, CEC 3.27.2)

Materiality

Fortis submits that the Commission should not impose a materiality requirement because "the cost increases or decreases arising from exogenous factors are non-controllable costs, and are therefore prudent by definition." The Companies further submit that any costs/revenues arising from non-controllable events would be recoverable in rates under cost of service-based ratemaking without any materiality threshold; therefore, the same logic should apply to PBR-based ratemaking. (Fortis PBR Final Argument, p. 47)

In response to CEC IR 3.32.6, Fortis states: "Exogenous factors should, in principle, flow through. However, when the changes are *de minimis* management may not seek recovery." Fortis further states that the "decision not to apply for recovery of a small cost must be treated as a practical determination, appropriately made by the Companies at the time and not by the Commission in advance" (Fortis PBR Final Argument, p. 48).

Fortis indicates that if the Commission determines that a materiality threshold is required, it should be based on a dollar value as this would be simpler than looking at ROE impact. Fortis referenced Ontario's thresholds which are in the range of $1 million to $1.5 million (T4:801) and further states that the Commission should take into account the relevant size of each of the Companies if the Commission decides to establish a materiality threshold (T4: 803).

Other Jurisdictions

Table 2.16 shows the criteria and materiality threshold established by the AUC:

Table 2.16 AUC Treatment of Exogenous ("Z") Factors

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
ALBERTA		
Z-Factor *(Unforeseeable events outside the control of the company, for which the company has no other reasonable opportunity to recover the cost within the PBR formula)*	1. The costs/impact of event must be attributable to events outside management's control. 2. The costs/impact of event must have a significant influence on the operation of the company 3. The costs/impact of event should not have a significant influence on the inflation factor in the PBR formulas. 4. The costs/impact of event must be prudently incurred. 5. The impact of the event was unforeseen (Z-Factor)	40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established

(Source: Exhibit B2-11, CEC 3.27.2, p. 67)

In response to CEC 3.31.1, Fortis provided the following assessment of the AUC criteria established for Exogenous or "Z"-Factors:

- Fortis considers criteria 1 and 5 to be implicitly established within the Companies' own proposals, as evidenced by the Companies' description of exogenous factors as "non-controllable" and "unforeseen" within their Applications.
- Fortis does not agree with criterion 2 and submits that "placing a materiality limit is most likely to deny prudent cost recovery and increasing the underlying risk."
- Fortis does not support criterion 3 because it considers it improbable that even a substantial rise in the inflation rate for the I-Factor in the PBR Formula could recover the costs of exogenous factors such as catastrophic events, major seismic incidents, and Acts of war, terrorism or violence. Fortis further asserts that the aforementioned exogenous factors are likely to have substantial impacts on economy-wide input prices.
- Fortis considers criterion 4 to be "unnecessary" because prudency in all expenditures, not just exogenous costs, is required by regulated utilities. (Exhibit B2-11, 3.31.1)

Table 2.17 shows the criteria and materiality thresholds established by the OEB:

Table 2.17 OEB Treatment of Exogenous ("Z") Factors

	Treatment	
Jurisdiction	**Applicability**	**Materiality**
ONTARIO		
4th GENERATION IR		
Z-Factor *(treatment for unforeseen events)*	1. Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived. 2. The amount must have been prudently incurred. 3. The amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor	1. Utility with Revenue Requirement less than or equal to $10 Million: $50 thousand Threshold 2. Utility with Revenue Requirement greater than $10 Million but less than or equal to $200 million: 0.5% of distribution revenue requirement Threshold 3. Utility with Revenue Requirement of more than $200 million: $1 million Threshold
EGD and Union (2008-2012 plans)		
Z-Factor *(non-routine events that were not otherwise recovered in the annual adjustment mechanism)*	1. The event must be causally related to an increase or decrease in the distributor's cost 2. The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate 3. The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism 4. The cost increase/decrease must be prudently incurred	The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of $1.5 million.

(Source: Exhibit B2-11, CEC 3.27.2, pp. 67–68)

Fortis provided an assessment of the OEB criteria during the Oral Hearing. The Companies consider criterion 1, which requires that amounts be causally related to the Z-Factor event, to be a given and therefore not necessary to be explicitly established as a criterion. Fortis also considers criterion 2 regarding prudency to be an unnecessary criterion since all costs incurred by the utility must be prudently incurred. Fortis does not agree with the OEB's third criterion establishing a materiality threshold for the reasons discussed previously in the analysis of the AUC criteria. (T4:805, lines 16–26)

Intervener Submissions

CEC submits that Fortis' proposal for treatment of exogenous factors provides the Companies with considerable discretion and that the proposal is misaligned with customer interests (CEC PBR Final Argument, p. 151). CEC identifies four key issues with Fortis' exogenous factor proposal:

1. Inadequate definition and lack of applicability criteria;
2. Lack of materiality clause;
3. Prudency not explicitly required; and
4. No obligation for "exogenous" savings to be brought forward on an equal footing.

CEC proposes the following criteria for exogenous factors:

1. Attributable entirely to events outside the control of a prudently operated Utility;
2. Directly related to the Exogenous event and clearly outside the base upon which the rates were originally derived;
3. Mitigated to the greatest extent by the Utility;
4. Prudently incurred; and
5. Greater than 30 basis points of ROE for the Utilities per year for exogenous events.

(CEC PBR Final Argument, pp. 157–158)

CEC submits that it is appropriate to establish criteria for determining whether or not an event is eligible for exogenous factor treatment so as to distinguish between costs that are justifiably extraordinary and costs that would otherwise be expected to be incurred under the PBR formula-driven spending. (CEC PBR Final Argument, p. 154)

CEC recognizes that there is an expectation of prudency in all expenditures but it still considers it necessary to include prudency as an explicit criterion. CEC submits that "as Z factors are explicitly intended to address extraordinary circumstances it is not unreasonable for the costs to be challenged." (CEC PBR Final Argument, p. 156)

CEC further recommends that Fortis be required to disclose all exogenous events that result in benefits to the ratepayers at the Annual Review. (CEC PBR Final Argument, p. 158)

No other Interveners made submissions on Fortis' proposed treatment for exogenous factors.

Fortis Reply

The Companies take issue with CEC's proposed criterion 3 which states that exogenous factors must be mitigated to the greatest extent by Fortis. The Companies submit that they are governed by the prudence test and any exogenous factor will be tested under their proposal. The Companies further submit that a guideline that is "focused on outcomes rather than prudent conduct, which CEC appears to be advocating, is contrary to the UCA" (Fortis PBR Reply, p. 45).

Fortis submits that CEC's proposed materiality threshold of 30 basis points of ROE is large and could impair the Companies' opportunity to earn a fair return. Fortis submits that to put CEC's proposal in context, the proposed materiality threshold is equivalent to greater than $4 million of FEI's O&M expense and is likely greater than $45 million of FEI's capital. (Fortis PBR Reply, p. 44)

Commission Determination

The Panel finds it necessary to include exogenous factors as part of the Companies' PBR plan in order to protect both the ratepayers and the shareholders. However, the Panel agrees with CEC that the Companies' proposal for exogenous factors is inadequately defined. **The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:**

1. **The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;**
2. **The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;**
3. **The impact of the event was unforeseen;**

4. **The costs must be prudently incurred;**
5. **The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.** This is further defined in the Section below**.**

The Panel considers the establishment of the above criteria necessary for transparency and greater clarity for all stakeholders as to why an amount is being brought forward for exogenous factor treatment. The criteria create an objective measure for assessing whether a potential event should appropriately be treated as an exogenous factor as opposed to solely relying on the Companies' judgment as to whether or not an amount should be brought forward for review by the Commission. The certainty provided by these criteria will improve the alignment between shareholder and customer interests.

Materiality

The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time. Establishing a materiality threshold also reduces the reliance on Fortis' judgment and instead creates a more transparent and objective process for determination of exogenous factor applicability.

In determining the appropriate materiality threshold, the Panel considered the balance between regulatory efficiency, providing the Companies with a reasonable opportunity to recover prudently incurred costs and allowing ratepayers the opportunity to realize the benefits of cost savings. The Panel also considered the materiality thresholds set by other jurisdictions, including Alberta and Ontario, as well as CEC's proposed materiality threshold of 30 basis points of the Companies' ROEs.

The Panel agrees with Fortis' submission that CEC's proposed materiality threshold is too high and could impair the Companies' opportunity to earn a fair return. The Panel also agrees with Fortis that basing a materiality threshold on a dollar value would be simpler and more straightforward.

The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate. The Panel has used its best judgement to arrive at this quantum. It is an amount that is proportional to the relative size of the companies and is also a dollar value.

Using FEI's February 21, 2014 Evidentiary Update filed as Exhibit B-1-5 as a proxy, the materiality threshold for exogenous factors for FEI is approximately $1.15 million [2013 Base O&M of $229,489,000*0.5%]. Using FBC's Application filed as Exhibit B-1 as a proxy, the materiality threshold for FBC is approximately $300,000 [2013 Base O&M of $59,848,000*0.5%]. While the Panel acknowledges that exogenous factors could relate to either O&M or Capital, it considers using Base O&M as the foundation for calculating the dollar value threshold for each Company to be reasonable as the prescribed amounts are within the range identified by Fortis in the Oral Hearing and are reflective of the relative sizes of FEI and FBC.

The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.

The Commission Panel further directs that exogenous events not be aggregated. The materiality threshold must be applied to the costs/savings of each exogenous factor event and the costs/savings for a specific event must exceed the materiality threshold in order to be eligible for exogenous factor treatment.

The Panel notes that exogenous factors must be treated symmetrically to create a fair balance of risk between the utility and ratepayers. **Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is any event resulting in savings must meet the criteria before it is accepted as an exogenous savings.**

Process for Exogenous Factor Applications

The Panel agrees with Fortis that it is not necessary to be overly prescriptive in terms of the timing of an exogenous factor application. The Panel recommends that to provide regulatory efficiency where possible, exogenous factor applications should be included as part of the Annual Review Process. However, Fortis may notify the Commission at other times during the year of exogenous events by letter to the Commission. The Commission Panel notes that consideration of exogenous events is not restricted to those raised by the Companies. Any party may make an application at any time in support of what it considers to be an exogenous event.

The Panel also agrees with Fortis that it is not practical to be overly prescriptive at this time as to the appropriate recovery mechanism for exogenous factor events. The Panel therefore accepts Fortis' proposal to address the appropriate recovery mechanism of exogenous amounts on a case-by-case basis. These recovery mechanisms could include, among other things, flow-throughs, deferral accounts, or true-ups. **The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.**

2.2.5 Flow-Through Items

Fortis proposes to flow-through various items which the Companies characterize as "known" or "foreseen" but not controllable. These flow-through items will be forecast each year during the Annual Review Process and thus not included within the PBR formula. For flow-through items which also have an accompanying deferral account, any variances between actual and forecast amounts will be added to the deferral account and amortized into rates outside of the formula. FEI already has a number of deferral accounts for these purposes; FBC is requesting establishment of certain deferral accounts for the same purpose. The issue of deferral accounts related to flow-through items is addressed in the next section. For flow-through items which do not have accompanying deferral accounts, Fortis proposes that the variances between forecast and actual amounts each year will be subject to the 50/50 Earnings Sharing Mechanism (ESM). (FEI Exhibit

B-11, BCUC 1.21.4, 1.21.5; FBC Exhibit B-7, BCUC 1.37.4, 1.37.5) Please refer to Section 2.3.1 for further discussion of the ESM.

FEI proposes to classify the following items as flow-through:

- Interest Expense;
- Return on Equity;
- Taxes;
- Pension and Other Post-Employment Benefits;
- Insurance Expense;
- Revenues;
- Depreciation and Amortization; and
- Rate Base other than Plant in Service (i.e. working capital, deferred charges).

(FEI Exhibit B-1, pp. 68–69)

FBC also proposes to classify the above items as flow-through, with the exception of non-Sales Revenue. FBC clarifies that it intends only to flow-through revenue from sales of electricity. (FBC Exhibit B-7, BCUC 1.37.4) However, in the Oral Hearing FBC further clarified that while the flow-through revenue is primarily electricity sales, there are other forms of tariff revenue included within the flow-through revenue category (T4:827, lines 9-14). Additionally, FBC proposes to flow through Power Purchase Expenses through the use of its Power Purchase Expense deferral account. (FBC Exhibit B-1, pp. 61–63; FBC Exhibit B-1-5, p. 1)

FEI described the ways in which it attempts to control each of the flow-through items to minimize the impact on customer rates, stating that for each of the proposed flow-through items there are "often components that are controllable and others that aren't." FEI further submitted that "[i]n most cases, it is the rate component of the expense that results in the item being deemed uncontrollable…" (Exhibit B-8, CEC 1.46.1)

In its response to CEC IRs 1.34 through 1.40, FBC described the variables which go into its determination of each flow-through item and also provided a discussion of the variables which are a function of company policy and practice and therefore may be somewhat controllable by the Company. (Exhibit B-10, CEC IRs 1.34 through 1.40)

Fortis submits that including uncontrollable costs within the PBR formula could result in windfall gains or losses to either the Companies or the ratepayers (Fortis PBR Final Argument, p. 42). Fortis also stated in the Oral Hearing: "…PBR is not about passing on uncontrollable costs between customers and companies, it's about incenting efficiencies and controllable costs." (T4:811, lines 13-15)

Insurance Expense

FBC's Projected 2013 Insurance Expense is $1,588,000 and its 2014 Forecast Insurance Expense is $1,734,000 (FBC Exhibit B-1, Table B6-5, p. 53). While FBC proposes to treat the entire insurance expense as flow-through, it is proposing to capture only the variance between forecast and actual insurance premiums in the Insurance Variance Deferral Account. (FBC Exhibit B-1, p. 263)

FBC stated:

> "[i]nsurance premiums are driven by insurance market conditions which change continually and are affected by large global losses, due to catastrophic events such as earthquakes, hurricanes and forest fires, as well as through general market conditions related to the unpredictability of investment returns and loss history… This lack of controllability around insurance premiums is what has driven the request for an Insurance Variance Deferral Account as part of the 2014-2018 PBR Application." (FBC Exhibit B-7, BCUC 1.187.3)

FBC further stated:

> "[t]he primary reason FBC proposes to only capture the variance between Forecast and Actual Insurance Premiums in the Insurance Expense deferral account is to provide for consistent treatment between Electric and Gas divisions." (FBC Exhibit B-24, BCUC 2.58.5)

Of the total 2014 Forecast for Insurance Expense for FBC, Insurance Premiums make up approximately 84 percent with a forecast amount of $1,460,000. The remaining 16 percent is attributable to First and Third Party Liability Expense, which is forecasted to be $274,000 for 2014. An additional component of Insurance Expense is Asset Valuations, for the 2014 Forecast this amount is zero. FBC states that Asset Valuations are incurred every four years and therefore, this expense is only included in the 2017 Forecast. (FBC Exhibit B-24, BCUC 2.59.1)

FBC stated that it "would not object to changing the method of determining O&M Expense in order to exclude only insurance premiums from the I-X formula, providing the 2013 Base O&M Expense is revised to include the forecast $274 thousand of First and Third Party Liability Expense" (FBC Exhibit B-24, BCUC 2.59.1).

FBC provided the following breakdown of insurance expense for 2013 Projected and 2014 Forecast:

Table 2.18 FBC Insurance Expense

	2013	2014 Forecast	Variance
		($000s)	
Premiums	$1,422	$1,460	$38
Appraisal Fees	$60	-	$(60)
1st & 3rd Party Claims	$106	$274	$168
Total	$1,588	$1,734	$146

(Source: FBC Exhibit B-24, BCUC 2.59.2.1)

FEI's entire Insurance Expense is attributable to Insurance Premiums (Exhibit B2-24, Undertaking No. 8).

Intervener Submissions

CEC raises the following concerns in its Final Argument about Fortis' proposed flow-through items:

1. The substantial dollar amount of the flow through items and the resultant loss of oversight of significant expenditures;
2. The loss of incentive to control partially controllable expenditures;

3. The combination of the incentive to reduce costs related to achieving revenues while flowing through the revenues, resulting in the lost opportunity for ratepayers;
4. The ability for a utility to flow through costs that might otherwise be included in its formulaic spending resulting in undeserved earnings at ratepayer expense.

(CEC PBR Final Argument, p. 172)

CEC further highlights its concern that by virtue of entering into the PBR regime and thus moving from a cost of service revenue requirement application to an annual review process, the Commission will lose the following:

1. Most of the oversight on flow through items; and
2. Openness and transparency.

(CEC PBR Final Argument, p. 172)

CEC points out that the flow-through items represent approximately 80 percent of FEI's revenue requirement or 60 percent of the delivery margin revenues (CEC PBR Final Argument, p. 173; Exhibit B2-8, BCUC 3.51.3). For FBC, approximately 82 percent of the revenue requirement is determined outside of the PBR mechanism (FBC Exhibit B-7, BCUC 1.21.1). CEC submits that given the fact that the majority of the costs and revenues are outside of the PBR formula, the result is a "significant loss of openness and transparency that would otherwise be afforded under a Cost of Service review." (CEC PBR Final Argument, p. 173)

CEC states that it "does not accept that the Utility is essentially unable to influence the vast majority of its costs." It submits that "[a]ctivities such as managing interest expense and taxes are key customer concerns that are tracked outside but are not entirely outside management control and under PBR there is limited to no incentive to manage these costs, nor appropriate oversight in the Annual Review." (CEC PBR Final Argument, p. 175) CEC further submits that "partially controllable areas may be a good place to apply more innovation especially since the earlier PBRs have apparently resulted in all the 'low hanging fruit' being already picked" (CEC PBR Final Argument, p. 176).

CEC also states that "incremental revenues in FEI are derived through RNG [Renewable Natural Gas], NGT [Natural Gas Transportation], new markets and increases in throughput and customer additions among others." CEC submits that it is "unreasonable to expect that the Utility will expend significant additional resources seeking projects that will increase customer load for customer benefit because such efforts are likely to increase costs included in the formulaic spending envelope and as such would not be in the Utilities' best interest." (CEC PBR Final Argument, p. 178)

CEC notes in its Final Argument that the Companies would not object to excluding only the insurance premiums portion of insurance expense from the I-X formula; however, CEC does not indicate whether it recommends this treatment (CEC PBR Final Argument, p. 189).

With regard to Rate Base other than Plant in Service, CEC submits "there is no particular need to have these variances subject to ESM… these items should be handled in a similar manner with other flow through items where the actual costs and revenues are the basis for customer rates." (CEC PBR Final Argument, pp. 190–191)

BCPSO submits that it is reasonable that only the insurance premiums portion of insurance expense be excluded from the PBR formula; however, BCPSO disagrees with FBC's proposed calculation of the insurance expense to be added to the 2013 Base O&M (BCPSO FBC Non PBR Final Argument, p. 3).

Fortis Reply

Fortis submits that its proposed flow-through treatment actually maintains the existing risk profile for customers and the Companies, and it is consistent with how these items would be treated under a cost of service model. Fortis further submits that eliminating flow-through treatment of uncontrollable costs would actually shift risk to the Companies. (Fortis PBR Reply, p. 39)

Fortis states that the flow-through items will be reviewed each year under PBR at the Annual Review, which is twice as often as under a two-year cost of service revenue requirements application.

Fortis further submits: "It is perplexing that CEC seems unwilling to rely on FortisBC's willingness to propose revenue generating initiatives under PBR when it seems to trust FortisBC under COS [cost of service] and the incentives in each case are identical" (Fortis PBR Reply, p. 40).

Commission Determination

Fortis' proposed lists of flow-through items are substantial when compared to the Companies' overall revenue requirements. FEI's proposal for flow-through items is comparable to its previous PBR plan, though certain items such as Late Payment Charges have been re-classified from controllable to non-controllable which has resulted in additional items being removed from the PBR formula in the current Application. Under FBC's previous PBR plan, fewer items were treated as flow-through in comparison to FBC's current PBR plan.

The Panel is concerned by the Companies' broad-sweeping approach to its treatment of flow-through items and believes that it is likely that certain components within the broader expense/revenue categories could be classified as partially controllable and therefore added back into the PBR formula. However, the Panel acknowledges that whether or not certain of the proposed costs/revenues are controllable, partially controllable, or non-controllable, it may not be appropriate to inflate these costs using the proposed I-X formula, and there is no evidence on the record which provides alternative formulaic methods to apply to these costs/revenues.

Additionally, while a substantial percentage of the Companies' revenue requirements are proposed to be classified as flow-through, the largest percentage relates to cost of gas for FEI and Power Purchase Expense for FBC, neither of which are appropriate for inclusion in the PBR formula. The Panel recognizes the importance of aligning the PBR plan with the X-Factor research. Since many of these flow-through items were not excluded from the X-Factor research, excluding them from the formula reduces the Companies' risk and therefore should be considered a benefit to them.

Based on the afore-mentioned considerations, the Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below. The Panel notes that this determination relates only to whether or not Fortis' proposed costs and revenues are approved to be treated as flow-through items. The subsequent section in this Decision (Section 2.2.5.1) addresses whether variances between forecast and actual flow-through costs/revenues are approved to be recorded in deferral accounts.

Insurance Expense

The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense. The remaining components of Insurance Expense must be added to the Companies' 2013 PBR O&M Bases. **The Panel directs the Companies to update the flow-through expenses in the Final Compliance Filings so that only Insurance Premiums are included in the Insurance Expense flow-through.**

Flow-Through Items Subject to 50/50 Earning Sharing

The Panel agrees with CEC that it is not appropriate to apply the 50/50 ESM to flow-through items. Through responses to IRs, Fortis has identified the following flow-through items to which it proposes to apply the 50/50 ESM: FEI's Industrial delivery revenues, and FEI and FBC's rate base other than Plant in Service. However, this treatment was not specifically described in either Company's Application so the Panel is unclear as to whether there are other flow-through revenues and/or expenses currently proposed to receive this treatment. **The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that the ESM mechanism is not to be applied to flow-through items.**

<u>Issues Raised by CEC</u>

With respect to the issues raised by CEC regarding the Companies' lack of incentive to develop revenue-generating projects during the PBR term, the Panel accepts Fortis' proposal to bring forward revenue-generating items at the Annual Reviews. The Panel does not consider the incentives regarding revenue generation to be any more or less impactful under a PBR regime than they are under a cost of service regime.

The Panel acknowledges CEC's concerns regarding lack of oversight and openness/transparency over the flow-through costs/revenues and agrees that a robust and thorough Annual Review process is a critical element of the PBR plan. This issue is addressed in Section 2.3.6 of the Decision as part of Annual and Mid-Term Reviews.

2.2.5.1 Deferral Accounts for Flow-Through Items

FBC proposes to establish a number of deferral accounts that are designed to specifically address some of its proposed flow-through items (for a discussion of flow-through items, see Section 2.2.5 of the Decision). The requested deferral accounts are:

- Tax Variance deferral account, with amortization in the following year;
- Property Tax Variance deferral account, with an amortization period of 3 years;
- Insurance Expense deferral account, with amortization in the following year; and
- Interest Expense deferral account, with an amortization period of 3 years.

FEI has previously received Commission approval to utilize the four deferral accounts listed above. The amortization periods for FEI's deferral accounts are the same as the amortization periods requested by FBC. (FEI Exhibit B-1-1, Appendix F4)

FBC submits that the deferral accounts are required in order to avoid windfall gains and losses given the uncontrollable nature of the proposed flow-through items. Additionally, FBC submits that this reduces the “controversy” around forecasting during the Annual Review process as any variances will be captured in the deferral account. (T4: 830)

FBC states that by utilizing these deferral accounts, customers only pay for expenditures that are actually incurred. FBC also submits that establishment of these deferral accounts will be consistent with FBC’s sister companies, such as FEI (FBC Non PBR Final Argument, pp. 78–80).

For the deferral accounts which are proposed to have a three year amortization period – the Interest Expense Variance deferral account and the Property Tax Variance deferral account – FBC submitted that three years is appropriate because it provides a reasonable balance between rate smoothing and ensuring that customers are paying for the true cost of service in a timely manner. Additionally, FBC noted that the requested amortization period is consistent with FEI’s approved amortization period for the same deferral accounts. (FBC Exhibit B-7, BCUC 1.190.6)

Further submissions on the nature of the proposed deferral accounts were also canvassed by the Commission Panel during the Oral Hearing Phase conducted on July 14, 2014 (Exhibit A-44).

<u>Intervener Submissions</u>

BCPSO has no concerns with FBC’s proposed approach to calculating forecast income and property taxes for 2014 (BCPSO Non PBR Argument, p. 14).

BCPSO points out that FBC’s main rationale for the difference in recovery periods for the two tax-related deferral accounts appears be that the proposed recovery aligns with the recovery periods for comparable FEI deferral accounts. BCPSO submits that the amortization periods for refund/recovery should be more principled than just “that’s how FEI does it.” These principles should include considerations of: matching cost/benefits to the appropriate period as well as rate stability. BCPSO submits that a one-year refund/recovery period would appear appropriate unless there is a significant balance that is likely to create material rate instability. BCPSO does not elaborate on why one year is more appropriate. (BCPSO Non PBR Final Argument, p. 18)

In its Final Argument, CEC appears to support the deferral treatment for these proposed flow-through costs because they "can provide customers with reassurance that they will be paying the actual costs rather than forecast costs." CEC is of the opinion that the utilities have some control over income taxes, property taxes and interest expense but indicated that so long as they are being treated outside of the PBR formula, there will need to be a robust review of these expenses during the Annual Reviews. (CEC PBR Final Argument, pp. 187–189)

During the Oral Hearing Phase on July 14, 2014, the Panel posed the question: "are these deferral accounts necessary," and further "what other options are available?" (FBC Exhibit A-44, FEI Exhibit A-38) CEC and COPE submitted that they support FBC's proposal to establish these deferral accounts with the additional suggestion by CEC that tighter oversight is required. Most of the interveners observed that these deferral accounts were not in place during the last PBR and questioned the need for them at this time. The ICG suggested that another method would be to take the 2013 inflation adjusted actuals into the PBR formula and eliminate the need for deferral accounts. IRG supported the proposal by ICG. Several interveners suggested that these deferral accounts are a transfer of risk from the utility to the ratepayer. (T8:1421, 1433, 1439, 1446–1451, 1462)

Commission Determination

In the previous section of the Decision, the Panel has determined that Fortis' proposed flow-through items, with the exception of a portion of Insurance Expense, are approved to be treated as flow-throughs to the customer. Now, the secondary issue is how to deal with the variances between forecast and actual amounts which will arise each year.

The issue before the Panel is whether establishment of these deferral accounts are necessary in order to enable the flow-through of expenditures. This issue applies to both FEI and FBC although FEI did not explicitly apply for any new deferral accounts for flow-through items.

The Panel notes that these deferral accounts were non-existent during FBC's last PBR and therefore does not agree that they should now be considered *necessary* in order to flow through these costs to ratepayers. During the last PBR, any differences between actual and forecast expenditures of prior years were identified in the Annual Reviews and then flowed through to the calculated revenue requirement for the current year. For example, incremental interest costs above the previous year's forecast were flowed through to the customer before the ROE sharing mechanism was applied. This method still allows for the flow through of these types of expenditures *without* the use of deferral accounts, particularly in the case where a deferral account has an amortization period of only one year.

FBC has requested the establishment of a Tax Variance deferral account and an Insurance Expense Variance deferral account with proposed amortization periods of one year. Because these deferral accounts are not required to flow through expenses under the PBR plan and the amortization periods proposed are limited to one year, **the Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.**

With regard to the requested Property Tax Variance deferral account and the Interest Expense Variance deferral account, the Panel acknowledges that the situation is somewhat different due to the fact that FBC has proposed three-year amortization periods for these deferral accounts. While the Panel recognizes that rate smoothing is an important consideration when setting amortization periods for deferral accounts, it does not consider this to be a determinative factor in the case of these requested deferral accounts. The variances between forecast and actual/projected property tax and interest expense do not appear large enough to warrant a need to spread the amounts over multiple years. Therefore, the Panel applies the same reasoning for these requested deferral accounts as we did to the Tax Variance deferral account and the Insurance Expense Variance deferral account.. The use of deferral accounts is not necessary to flow-through variances between forecast and actual expenses under PBR. **Accordingly, the Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.**

The Panel notes that the denial of these deferral accounts does not impact the determination that the actual expenditures of these items should be flowed-through to customers (see previous section in this Decision). In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FBC to true-up these costs each year**. Finally, the Panel also clarifies that these flow-through items should be applied first, and then a calculation of the earnings sharing mechanism will follow. This is the same treatment as conducted by FBC in its last PBR.

The Panel notes the distinction between FBC and FEI's current treatment of many of the flow-through items in that FEI has previously received approval for the deferral accounts requested by FBC in the Application.

However, the Panel refers to its determinations made above for FBC and re-iterates that these deferral accounts are not necessary to flow through costs to ratepayers. **Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account**.

For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.

In order to reflect in rates the actual costs related to these flow-through items as close as possible to the period in which they were incurred, **the Commission Panel directs FEI to true-up these costs**

each year. Finally, the Panel also clarifies that these flow-through expenses should be applied first, and then a calculation of the earning sharing mechanism will follow. In other words, the same treatment as conducted by FBC in its last PBR should be followed.

2.2.6 Growth Term

2.2.6.1 O&M Growth Term

Both utilities include a term in their O&M formula to account for an increase in spending that they submit is required to account for net additional customers added to the system. The term is a ratio between the current year's expected average number of customers and the previous year's actual number of customers:

$$(AC_t/AC_{t-1})$$

where AC is the average number of customers that the utility serves in the year t or t-1. The effect of this term, all else equal, is to increase (or decrease, as the case may be) the previous year's O&M spending by that ratio. (FEI Exhibit B-1, p. 57; FBC Exhibit B-1, pp. 52–53)

Intervener Comments

BCPSO submits that "[w]hile growth in customers is a driver of costs, the history of costs does not support both an increase related to inflation and an increase related to growth" (BCPSO PBR Final Argument, p. 8).

Table 2.19 shows FBC's actual O&M per customer.

Table 2.19 FBC Actual Controllable O&M per Customer

	2008	2009	2010	2011	2012
Controllable O&M ($000)	39,860	40,113	39,649	41,411	40,087
Number of Customers	108,722	110,286	111,551	112,754	113,587
Actual O&M per Customer	$367	$364	$355	$367	$353

(Source: FBC Exhibit B-11, BCPSO 1.37.3)

For FBC, over the five years of actual results, the total O&M increases from $39,860,000 in 2008 to $40,087,000 in 2012, an increase of 0.14 percent in controllable O&M, compared to a 4.4 percent increase in customers over the same period. BCPSO's expert, Mr. Bell submits that history does not support the need for a growth factor for O&M for FBC because the actual O&M per customer remains fairly constant. (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

Table 2.20 FEI Actual Controllable O&M

	2010	2011	2012	2013
Number of Customers[9]	824,125	830,390	834,888	840,721
Actual O&M[10] ($ 000)	206,518	213,606	212,269	233,891
Actual O&M per customer[11]	$251	$257	$254	$278
Less Pension/OPEB/Insurance[12] ($ 000)	13,443	14,538	21,529	21,255
Total Controllable O&M ($ 000)	193,075	199,068	190,740	212,636
Controllable O&M per Customer	$234	$240	$228	$253

BCPSO states that for FEI, the 2012 cost per customer is $254, which is only 0.40 percent higher than the 2011 amount of $253 (In FEI Exhibit B-6, BCPSO 1.16.2, FEI provided $253 as the PBR

9 Exhibit B-54 Fortis Panel IR Response, Attachment 2.1, which includes 2012 customer count adjustment of 14,892 extended back to 2009.

10 Exhibit B-1-5, Evidentiary Update February 2014, Table C3-1.

11 Calculated as Total PBR[11] Tracked O&M/Number of Customers.

12 Exhibit B-54 Fortis Panel IR Response, Attachment 2.1.

tracked O&M per customer as opposed to the $257 as shown in Table 2.20 which is calculated from the information in the Panel IR). This increase is lower than the inflation increase for that period, and in its view, does not demonstrate a need for a growth factor. It states that "[p]roviding a growth component, in excess of the I-X would not provide an incentive to continue this pattern of constant cost per customer." (FEI Exhibit C5-6, BCPSO Evidence, p. 13)

Fortis disagrees, stating "[t]he simple fact that the results are provided on a per customer basis means that customer growth is reflected implicitly in the calculations already" (FEI Exhibit B-44, pp. 3–4).

However, Mr. Bell explains that if there was a need to allow for both inflation and a growth component, "one would expect to see that the O&M per customer would be going up on a constant basis, and I didn't find that, and so that was how I reached the conclusion that to have an inflation factor as well as a growth factor would produce forecasts that are likely in excess of what is." (T6:1307)

Table 2.21 FBC FTE Count for the Period 2010 to 2012

2010	2011	2012
537.66	527.63	542.13

(Source: FBC Exhibit B-11, BCPSO 1.71.2)

BCPSO also argues that even if O&M costs do increase with growth, costs aren't as highly correlated to growth as the proposed formula suggests. It cites FBC's FTE levels, shown in Table 2.21 and FBC's comment that "[t]he FTE levels for 2013 and for the remainder of the PBR Period are expected to be at a level similar to 2012 on a total company basis." From this, BCPSO concludes that: "[g]iven the fact that the history of O&M does not support a growth factor, and the fact that FBC itself does not foresee growth in staff, a growth factor is not needed." (FBC Exhibit B-11, BCPSO 1.71.2; FEI Exhibit C5-6, p. 13)

Fortis submits that "[a] valid analysis cannot be based on a simple review of historical results, as they are highly dependent on the time period chosen and the assumptions made." (FEI Exhibit B-44, FEI Rebuttal Evidence to BCPSO, p. 3)

During the Oral Hearing, Mr. Bell testified that he agreed that as a utility adds customers, it must add various facilities and resources to serve those customers. However, in his view, "[u]sually a utility does not add incremental resources for each new service," because the utility would not "require additional resources immediately to maintain those facilities." Mr. Bell also stated that "[a]s you add more and more, eventually you need to add more resources" and that "when you reach a threshold" there will be a cost associated with adding the requisite resources. Mr. Bell agreed that these incremental costs apply when either FEI or FBC add customers. (T1:1311–1312)

In Fortis' submission, there are two reasons why it is reasonable to use customers to account for growth in the context of O&M. "First, adding customers directly impacts O&M. Costs for billing and meter reading are directly correlated to customer count and will increase as customer count grows. Costs for transmission and distribution operations and maintenance are indirectly related to customer count and will incrementally increase as customer and customer capacity requirements grow." (FEI Final Argument, p. 33)

B&V submits it is appropriate to use customers as a reasonable proxy for the capacity variable in the formula because "it effectively adds an estimate of additional O&M expense associated with system growth to the plan's revenue adjustment." (FEI Exhibit B-1, p. 57; FBC, Exhibit B-1, p. 53)

In Fortis' view, changing the O&M formula by removing growth, as advocated by Mr. Bell, is tantamount to increasing the productivity improvement requirements imposed on the Companies. Further to this, Fortis believes the structure of the O&M formula should remain the same as it has been in the past so that the productivity improvement requirements are clearly set out in the X-Factor, and not disguised in some combination of the X-Factor and growth or other elements of the formulas. (FEI Exhibit B-44, pp. 3–4)

CEC states that "there is a solid rationale for having an explicit term for operating scale in an escalation formula" (FEI Exhibit C1-22 BCUC 2.5.1).

2.2.6.2 Capital Growth

Table 2.22 shows the growth terms Fortis proposes for its Capital Formulas.

Table 2.22 Capital Formula Growth Terms

	FEI	FBC
Growth capital	(SLA_t/SLA_{t-1})[13]	(AC_t/AC_{t-1})
Sustainment Capital	(AC_t/AC_{t-1}).	(AC_t/AC_{t-1})
Other Capital	(AC_t/AC_{t-1}).	(AC_t/AC_{t-1})

(Source: FEI Exhibit B-1, pp. 62-64; FBC Exhibit B-1, pp. 56-67)

B&V states that

> "[o]f the three categories of regular capital expenditures that FEI has included in its PBR formula, Growth Capital differs from Sustainment and Other capital in that it is primarily driven by customer additions. In particular, Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. FEI will re-forecast the level of service line additions for upcoming years (driven off of the gross customer additions) in the PBR Annual Reviews." (FEI, Exhibit B-1, p. 62)

With regard to FEI's sustainment and other capital, B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the

[13] SLA = Service Line Additions

expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system. (FEI, Exhibit B-1, p. 63)

Concerning FBC, B&V states that

> "in actual fact, growth, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no straightforward measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since extensions of the system to serve customers adds new capacity to the system." (FBC Exhibit B-1, p. 56)

Table 2.23 shows FBC's historic capital spending for the years 2007 through 2012.

Table 2.23 FBC Total Non-CPCN Capital $ thousands)

	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Generation Capital	19,781	15,355	18,411	17,555	15,956	6,985
Transmission-Dst Capital	95,575	76,321	72,416	104,488	48,109	35,734
Other Capital	13,834	7,912	8,342	8,448	12,145	9,674
Total Capital	129,190	99,588	99,169	130,491	76,210	52,393

(Source: FBC Exhibit B-15, ICG 1.36.1)

Table 2.24 shows capital expenses per customer FBC.

Table 2.24 FBC Capital Spending per Customer ($)

	2007	2008	2009	2010	2011	2012
Customer Count	108,722	110,286	111,551	112,754	113,587	108,722
Generation Capital per cust.	$182	$139	$165	$156	$140	$64
Trns/Dst Capital per cust.	$879	$692	$649	$927	$424	$329
Other Capital per cust.	$127	$72	$75	$75	$107	$89
Total Capital per cust.	$1188	$903	$889	$1,157	$671	$482

(Source: FBC, Exhibit B-11, BCPSO 1.37.3)

Intervener Submissions

BCPSO states that there is no pattern of correlation between capital and customers and therefore submits that, "there is no demonstrated need for a growth factor for FBC capital" (FBC Exhibit C5-6, BCPSO Evidence, p. 14)

CEC submits that "there may be factors related to growth that increase costs but submits that they do not do so in a liner manner and that providing for both inflation and growth in a linear manner results in an unreasonable spending allowance." (CEC PBR Final Argument, p. 68)

Commission Determination

Should the PBR Formulas include a Growth Term?

Mr. Bell suggests that because O&M expenses per customer haven't risen as quickly as inflation, there is no need for the O&M revenue formula to account for growth. The Panel does not agree with this interpretation. It is not possible to draw this conclusion because the evidence is inconclusive. The Panel agrees with Fortis that a historical examination of per-customer spending doesn't provide any information concerning the link between customer growth and costs incurred to meet the growth.

It is possible for expenses to be decreasing, for example due to efficiencies, at the same time that they are increasing due to an increase in the number of customers. Similarly, efficiencies could potentially drive a reduction in FTEs at the same time that an increase in customers drive an increase in the number of FTEs required.

With regard to efficiency driven cost reductions, the Panel notes that previously, FBC was under a PBR regime and during this period the X-Factor was approximately 2 percent for 2007, 2 percent for 2008, 3 percent for 2009 and 1.5 percent for 2010 and 2011. Inflation ran at approximately 2 percent during that period. (FBC, Exhibit B-1-1, Appendix D 1, p. 25) Given that FBC underspent its formula spending envelope during the last PBR, it is not unreasonable to expect that actual O&M per customer increased at a rate near or less than that of inflation.

Considering the issue of the effect of growth on spending generally, the Panel notes that a utility that services one million customers incurs more spending – both O&M and capital – than does a utility that serves 100,000 people. Therefore, it is reasonable to conclude there are cost increases associated with growth. Further, BCPSO acknowledges that customer growth is a driver of costs. The Panel is persuaded that it is appropriate that a revenue cap formula, such as the one Fortis proposes, should account for growth. However, what is at issue is the correlation between the actual number of customers and spending and therefore, what the growth factor should be.

Is the Growth Factor Fortis proposes the Correct One?

With the exception of FEI's growth capital formula, all growth terms are based on the number of customers. FEI's Growth Term is based on the number of service line additions. The Growth Term Fortis proposes for all formulas, except growth capital for FEI, is linear with a scale factor of 1. That is, if the number of customers is doubled, the spending envelope is, all else equal, doubled; if the number of customers triple, the spending envelope is tripled; etc. This relationship is the same over any range of customer numbers. For FEI's growth capital formula the same relationship applies to the number of service line additions.

However, growth related expenses may not be correlated in the manner suggested by the formula. Both capital and O&M growth related expenditures may be somewhat lumpy, causing spending requirements to increase in a step-wise manner. In this regard the Panel agrees with Mr. Bell's observation that costs only increase when a threshold in growth is reached.

For example, over a sufficiently large range of customer additions, there is correlation between the number of customers and the number of service trucks needed – increase the number of customers and there will be an increase in the number of trucks required. However, increasing by one customer, or ten, or even one hundred may not trigger the need for an additional truck. It is only when a threshold of new customers is reached that the need for a new truck is triggered and both the capital and O&M expenses associated with that new truck are required.

CEC argues that while costs do increase with growth, they may not do so in a linear manner. The Panel agrees this may be the case, and considers two examples of where costs do not increase linearly. A non-linearity may arise because of economies of scale. A utility that serves a million people may not incur 10 times the O&M spending as does a utility that serves 100,000. As the number of customers increases, the scale factor decreases. Potentially, many different scale factors could apply as the number of customers increases or decreases. Similar scaling issues may also apply to FEI's proposed growth capital Growth Term.

The issue of correlation between costs and the number of customers is further underlined by FBC's comments in its Non-PBR Reply (pp. 11–18). In response to a suggestion by CEC that customer service related costs be reduced to reflect a reduced number of customers, FBC submitted that it is inappropriate because "the costs for that department do not decline commensurately." Although this statement was made by and about FBC, it applies equally to FEI.

If the growth term in the formula doesn't accurately reflect Fortis' actual growth related spending requirements, in the Panel's view, the Growth Term should be adjusted. The adjustment may be in the form of a calibration to the proposed growth term – i.e. $0.5*(AC_t/AC_{t-1})$ instead of $*(AC_t/AC_{t-1})$.

Further, the calibration factor may be different for different levels of AC. However, there is no evidence of what, if any, calibration is required.

Of further concern to the Panel is that the Growth Term relies on Fortis' estimate of the average number of customers in the upcoming year. In the event of over estimation, the spending envelope will be larger than otherwise required, thereby resulting in an opportunity to over-collect. Although ratepayers and shareholders share, on a 50:50 basis, any over-collected amounts, this represents a transfer of wealth from the ratepayer to the shareholder. If estimates do not display any significant bias either upward or downward over time, this is not an issue. However, consistent overestimates of customer growth will result in an unjust transfer from the ratepayer to the shareholder.

In Fortis' proposed PBR mechanism, if there is an over estimate, there is never an opportunity for true-up. This is a similar to the potential for bias that we observed in the use of a forecast inflation term.

Given these issues, the Panel is not persuaded that the proposed Growth Term is appropriate. We consider that the Growth Term as proposed has the potential to provide a more generous spending envelope than is warranted. **Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service live additions two years previous.** The Panel recognizes that this introduces some lag into the formula calculation, but we consider it necessary in order to eliminate the potential of upward bias. This is the same approach we took in the case of the Inflation Factor. **Accordingly, the Commission Panel approves Growth Terms of 0.5 * (SLA_{t-1}/SLA_{t-2}) for FEI's growth capital and 0.5 * (AC_{t-1}/AC_{t-2}) for all other cases.**

If Fortis has evidence that a different growth term is more appropriate, it can bring forward that evidence at any time.

2.3 Key PBR Plan Components

2.3.1 Earnings Sharing Mechanism

An Earnings Sharing Mechanism (ESM) is a mechanism added to some PBRs to allow for the sharing of efficiency cost savings between the customer and the utility. ESMs are described as "regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and the benefits of the PBR plan." In addition, if symmetrical, they serve to soften the impact of unintended consequences such as excessive utility gains or losses within a PBR. FBC states that in regulatory literature there are two schools of thought regarding ESM usage. One school asserts that ESMs decrease the incentive power of the PBR plan and impose additional regulatory burden and cost. The other indicates that ESMs allow for improved cost tracking and mitigates concerns with excessive profits or losses and represents a fair approach to sharing the benefits of a PBR plan. (FBC Exhibit B-1, p. 64)

Fortis, citing support from B&V, has proposed that a symmetric ESM be made a component of the PBR Plan. The proposal is for an ESM based on the 2007 PBR which called for sharing on a 50:50 basis among customers and the utilities of earnings either above or below the allowed ROE in a given year. The plan is for the shared earnings to be projected during each Annual Review process but finalized after year-end when actual results are known. (FBC Exhibit B-1, pp. 64–65)

Intervener Submissions

CEC submits that the proposed plan has eliminated an opportunity for the customer to address concerns and adjust earnings accordingly and has also eliminated the no surprise clause and the line-by-line review process to determine levels of sharing. CEC considers that these changes represent a departure from customer interests. CEC also submits that the ESM does not limit customer risk as it does not limit the extent of utility financial earnings and serves to support a longer period between rebasing because the utility must share its earnings. This extended period has its downside for customers, one of which is the lack of transparency as there is no oversight over the five-year period. This extended period provides an additional three years with which to take advantage of additional earnings as compared to a standard two-year cost of service process. (CEC Final Argument, pp. 109–120)

None of the other Interveners had specific comments with regard to the ESM.

Fortis Reply

Fortis, in Reply, notes much of what CEC has to say relates to the PBR generally and are out of context. With respect to the ESM failing to limit the risk to the customer because it does not limit the earnings available to the utility, Fortis points out that the ESM serves to mitigate risk as there is equal sharing of both upside and downside results thereby creating balance. (Fortis PBR Reply, p. 45)

Commission Determination

The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers. In our view, the inclusion of an earnings sharing mechanism balances the interests of the customer and the utility. That is, to the extent that there are gains or losses relative to the approved ROE, the fact that they are shared on a 50:50 basis between the ratepayer and the utility is reasonable. The Panel notes that the purpose of implementing a PBR mechanism is to provide an environment where efficiencies are created through actions initiated by the utility. Accordingly, there is an expectation that all things being equal, the Fortis utilities will, over the course of this PBR, generate efficiency savings resulting in earnings which allow them to exceed the approved ROE return. Fortis has proposed that these savings be shared. To deny the customer the opportunity of sharing these savings would not be in their interest. However, the Panel does acknowledge that in approving a symmetrical ESM we are, in effect, reducing the risk faced by Fortis on the downside and there is a potential negative rate impact in the event of unforeseen circumstances. However, given the historical performance of the Fortis utilities in achieving their approved ROE, we consider this downside risk to be limited.

The Commission Panel has considered the submissions of CEC with respect to the inclusion of an ESM. The points raised by CEC seem to be more concerned with the approval of a PBR and how it is designed than with the ESM itself. These include matters such as the elimination of the no surprise clause, the potential for earnings by simply not spending and the proposed term of the PBR relative to a more traditional cost of service agreement with a shorter time frame. While the Panel acknowledges that these matters are important, we agree with Fortis that with respect to having an ESM or not, CEC's arguments are out of context. To the extent possible, matters such as these will be dealt with in other parts of this Decision.

Given the apparent lack of trust between the parties in this proceeding and concerns with the potential to game the results, the Commission Panel considers the inclusion of an ESM to be a positive measure in that there is a sharing of gains or losses and does not favour either side. Additionally, the Panel notes that none of the parties have proposed its elimination. Given these factors, the Commission Panel considers an ESM mechanism to be appropriate at this time.

2.3.2 Efficiency Carry-Over Mechanism

An Efficiency Carry-Over Mechanism (ECM) is a plan component that allows the utility to receive benefits in periods following a PBR period for savings resulting from measures taken and costs incurred during the PBR period. Fortis describes the ECM as a means to incent the utility to pursue efficiency initiatives throughout the entire PBR period. It is justified on the basis that without it, the utility will have decreasing levels of motivation to initiate efficiency improvements as the PBR period moves forward. Fortis states this is because under a fixed-term PBR, the payback to a utility's investment in efficiency improvements is earned only on those savings up to the end of the PBR. Therefore, the utility is motivated to initiate changes resulting in savings early in the PBR period to maximize its payback or in some cases to put off such projects because there is insufficient time remaining in the PBR to earn a return even recover costs. Inclusion of an ECM allows the utility to initiate efficiency improvements later in the PBR period but continue to earn a share of the return into the period following the PBR. (FEI Exhibit B-1, pp. 72–73; FBC Exhibit B-1, pp. 65–68)

The Commission approved the use of an ECM in the 2004 PBR Plan for FEI. The ECM allowed accumulated capital carrying cost and depreciation benefits to continue at a rate of 2/3 in the first year and 1/3 in the second year following the end of the PBR. In the current Applications, Fortis is proposing an enhanced ECM for both FEI and FBC which includes two additional components; the inclusion of O&M savings in addition to capital and the use of a five-year rolling carry-over period for the sharing of savings following the year in which the improvement occurred, regardless of when the PBR period ends. Fortis states that including O&M savings in the ECM maintains a balance between capital and O&M savings initiatives, and that the inclusion of a five-year rolling carry-over period eliminates concerns with timing from decision-making and promotes ongoing efficiency improvement initiatives. (FEI Exhibit B-1, p. 74; FBC, Exhibit B-1, pp. 66–67)

Based on this, Fortis proposes implementing the five-year carry-over plan where the incremental O&M and capital savings are calculated as the sum of:

1 Variance of current year formula based O&M less cumulative O&M savings from prior years of the PBR Plan; and
2. Current year plant additions savings relative to current year allowed plant additions derived from PBR capital formula multiplied by a base rate factor of 12 percent (15 percent for FEI).

Fortis states that the 12 percent rate base factor represents the avoided revenue requirements from reduced capital expenditures. Avoided revenue requirements components include return on rate base, depreciation expense and associated taxes. The 50:50 sharing between ratepayer and shareholder will apply to the ECM in the same manner as it does within the PBR period.

Fortis states that the inclusion of an ECM has the support of B&V "because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity in the later years of the PBR Plan." This is possible because disincentives to install new productivity initiatives as the PBR Plan ends do not exist. (FEI Exhibit B-1, pp.74–75; FBC Exhibit B-1, pp. 67–68)

Intervener Submissions

CEC considers the proposed ECM to be detrimental to ratepayer interests and does not agree with the mechanism proposed by Fortis. CEC recommends the ECM as proposed by the utility be rejected outright. It submits that its issues with the proposed ECM mechanism are significant and that the theory and rationale behind the mechanism is incorrect and the benefit claims are "presumed rather than actual."

CEC considers the inclusion of O&M in the ECM represents additional ratepayer costs with no additional benefits. This "amplifies the underspending of an overly generous formula." CEC further states that in addition to the inclusion of O&M and a rolling carry-over mechanism, the current ECM proposal includes a full payment rather than a declining one, has a longer term and includes an increase of the rate base benefit factor (from14 percent to 15 percent for FEI). It submits that these changes are detrimental from a customer perspective and are not well supported in evidence.

CEC has numerous other issues with the proposed ECM mechanism. These include perverse incentives, basing rewards or benefits on a presumption that they last for at least 5 years and its inclusion eliminates benefits which would have been derived from rebasing. In CEC's view the key issue is the determination of the appropriate time for rebasing embedded savings and further submits that this could vary considerably based on the nature of the efficiency project and life of potential savings.

CEC accepts that there will be instances where there will be value in the utility having longer payback periods available. These may be warranted where the utility has made a significant investment in efficiency measures. However, in such instances deferral accounts could be used as a mechanism to manage such longer-term payback periods. These would not limit the payback to any term and would reduce risk for the utility and ratepayers in addition to ensuring that there will be greater Commission oversight. (CEC Final Argument, pp. 23, 125–130)

BCPSO notes that ECMs are not common in PBR plans, pointing out that Fortis was only able to identify two jurisdictions in Canada where they exist. BCPSO's concern with the use of ECMs in this instance is that Fortis is using the building block model where:

> "the utility can under spend on O&M and capital in each year and earn superior returns, and then claim an ECM. But there is no need, in circumstances where the utility can benefit from underspending the formula, to also provide an additional incentive to underspend in the form of an ECM." (BCPSO Final Argument, para 29, p. 11)

BCPSO's overarching concern is best summarized in the following statement: "the issue is that the company can spend less O&M and Capital, and in effect double dip, gain during the PBR period by spending less, and then achieve superior returns after the end of the PBR for the same reductions." It submits that there is not a need for an ECM in this PBR. (BCPSO Final Argument, pp. 11–13)

BCPSO points out that Fortis' ESM is also a Loss Sharing Mechanism, in that it provides for a 50:50 sharing of earnings above and below the allowed ROE. In the event Fortis fails to earn its allowed return during the PBR period, the ESM requires ratepayer contribution above the formula derived costs during the PBR term, then additionally, the ECM requires ratepayer's shared contributions after the PBR term. (BCPSO PBR Final Argument, p. 14)

ICG does not support an ECM as it "does not believe that regulatory parameters affect efficiency initiatives in the manner suggested by FBC, at least sufficiently to justify the excess returns." ICG submits that an ECM must not be a windfall for the utility and the Panel needs to be certain that its inclusion will benefit customers. However, if approved, the efficiency gains have to be measured and must be allocated symmetrically. That is "if efficiency gains are achieved then the utility receives a higher return, but if efficiency losses are realized then the utility receives a lower return." (ICG Final Argument, pp. 23–25)

ICG considers the utility to be responsible for achieving and then measuring efficiency savings. It provides a hypothetical example where the utility spends $1 million on an efficiency initiative to achieve a $500,000 efficiency saving. If the savings are than expected results then the utility, not the customer, pays the difference between the cost of the efficiency measure and actual savings. It appears that ICG is recommending that the 50:50 sharing mechanism which has been proposed by Fortis and approved by the Panel in Section 2.3.2, be suspended for the ECM applied beyond the end of the PBR period. In this way, the utility would receive the credit for any gains and also bear any losses related to an approved ECM in the period following the PBR. (ICG Final Argument, pp. 23–25)

Fortis Reply

Fortis, in Reply, views the position taken by CEC as to the "the customer continu[ing] to reward the utility when there are no earnings which it is 'sharing with the customer'" as "starting from the wrong premise." It reiterates that the inclusion of an ECM is designed to make the company whole for the costs not yet recovered in rates prior to the end of the PBR. In addition, it takes issue with CEC's suggestion that the lack of research and documentation is the reason the ECM should be rejected pointing out that the concept is familiar in that ECMs have been used in previous PBRs and are currently in place in Alberta and Quebec. Fortis also notes that Dr. Lowry's comments on ECMs were largely supportive of including this component.

Fortis had no additional comments regarding CEC's concerns with respect to term length of the current ECM proposed and the move away from a declining payment schedule which had characterized earlier iterations.

Fortis also withheld comment on CEC's contention that the time for rebasing savings is not always five years and varies by the nature of the efficiency project and the length of potential savings. The Commission Panel notes that Fortis had previously addressed CEC's suggestion that as an alternative deferral accounts could be used as a mechanism to manage longer payback periods. In response to CEC FEI 3a.38.5 Fortis states: "FEI believes that a deferral account approach would involve more regulatory process and would run counter to the objectives under PBR of streamlining the regulatory process and aligning the interests of customers with the interests of the utility." Fortis further states that such an approach may be possible and could be applied to larger scale initiatives but it would be less practical to employ this with smaller scale programs. (Fortis Reply, pp. 49–52; FEI Exhibit B2-2, CEC 3a.38.5)

Fortis states in response to BCPSO's comments that the underlying premise of its argument "is that the Commission is incapable of doing its job" and the inclusion of an ECM represents a significant downside for the customer. In Fortis' view, the Commission should be reviewing this Application on the basis that it will be able to determine just and reasonable rates when next there is a COS Application. (Fortis PBR Reply, pp. 47–49)

Fortis makes no reply to the ICG submissions.

Commission Determination

The Commission Panel cannot help but acknowledge the level of cynicism and distrust implicit in the submissions of the interveners with respect to the inclusion of an ECM in the Fortis PBR. It is clear from these submissions that the interveners view the proposed ECM as being one-sided and very much in favour of the utility. BCPSO is perhaps most emphatic when it states that in spite of under spending on both O&M and capital in each year and earning what might be described as superior returns, Fortis then gets to claim their part of the ECM in the period subsequent to the PBR period. Concerning BCPSO's comments, Fortis' interpretation is that it is based on the underlying premise that "the Commission is incapable of doing its job" and in its view the Commission should consider this Application from the perspective that it will be able to determine just and reasonable rates in the next COS Application. The Commission Panel agrees. Our review of this Application should lead to determinations that, to the best degree possible, we can anticipate and control the ability of the utility to "game" any element of the PBR and minimize opportunities for Fortis to benefit at the expense of the ratepayer.

In the view of the Commission Panel, the ECM proposal put forward by Fortis favours the utility and puts the ratepayer at risk for future payments following the PBR period with no assurance that the savings will carry forward. Specific concerns of the Panel include:

Five-Year Rolling Carry-Over Period

As structured, the ECM is based on the assumption that any savings which occur warrant a payback period (which is shared between the ratepayer and the utility) of five years. There has been no compelling evidence to suggest that five years is an appropriate time period for all or any efficiency initiatives. The Panel notes that ECMs do not appear to be commonplace and, where they exist, no evidence has been presented to suggest they have a five-year payback period. There are variations of ECMs in both Alberta and Gaz Metro but neither of these extend for a five year period. (T2:305)

The Use of a Formula Driven O&M ECM Calculation

The ECM, as proposed, rewards additional O&M savings in later years of the PBR by carrying the reward for them over to the post PBR period. This, in the view of Fortis, provides an incentive to continue to develop efficiency measures in later years of the PBR. The Panel acknowledges there is some logic to this but also notes that there has been no attempt in the proposal to separate those savings that are related to an actual initiative from those that result from simply not spending the funds or being unable to do so due to circumstances unforeseen by Fortis. In either case, the savings would apply and carry over (albeit shared with ratepayers) into the post PBR period. Even if identified during the rebasing process, there would be instances where the Commission would have no option but to approve the inclusion of these savings as justified new expenses in future revenue requirements while, at the same time, allowing the savings for them to carry forward into the post PBR period. The Commission Panel considers the risk associated with this to be considerable. Moreover, while incenting the development of efficiency initiatives later in the PBR period, the Fortis proposal equally incents under-spending or gaming the formula.

The Use of a Formula Driven Capital ECM Calculation

Many of the concerns raised with respect to the O&M ECM formula also apply to capital. Delay of projects, whether through circumstances beyond the utility's control or by design are a commonplace occurrence. To apply a formula without consideration of the individual circumstances would leave it open for unintended consequences and potentially a windfall for the utility.

Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology. However, the Panel acknowledges that there will be instances where there are efficiency related programs with associated costs which may remain unimplemented if an ECM did not exist. Therefore, in spite of the concerns raised, we are persuaded that there is value in the inclusion of some form of ECM mechanism as a means of incenting the development of efficiency initiatives throughout the PBR period. However, the ECM mechanism must be transparent, flexible and allow a decision to be made on each initiative based on its individual circumstances taking into account the benefits, the period of the benefits, costs and likelihood for success. In addition, there is a need to track these investments and determine whether they deliver on the promised benefits. Creating a formal process to deal with ECM initiatives will provide greater transparency and hopefully reduce the distrust and cynicism referred to earlier.

Accordingly, the Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative;

1. **ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year.**
2. **For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid.**
3. **Parties will have the opportunity to comment on the proposal.**

If agreed to by the parties, the proposal will go to the Commission with a recommendation for approval. If not agreed to, the proposal will go to the Commission for a Decision or development of further process. Based on these submissions, the Commission will make a determination as to the justification of each ECM proposal on a case by case basis.

2.3.3 Managing Service Quality

2.3.3.1 Purpose of SQIs

One of the more contentious issues with the Fortis PBR proposal is determining the role that SQIs play within a PBR Mechanism. SQIs have been recognized as an effective way to measure the performance of a utility from a variety of perspectives. These may include but are not limited to safety, customer service and service availability. As noted by FEI in its Application, SQIs "are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality" (FEI Exhibit B-1, p. 77). This raises the question that if service quality has been compromised in the interests of cost savings or efficiencies or simply suffers with no linkage to a particular act, what should be the consequences?

The Fortis proposal envisions that each year during the Annual Review, it will present the FEI and FBC projected results for SQIs to the parties and the related discussion will serve to provide an understanding of issues affecting the Companies' ability to meet established benchmarks. Fortis has further clarified this issue by stating that unsatisfactory performance as measured by non-financial SQIs are more appropriately assessed at the mid-term review allowing for measurement over a longer time horizon. (Exhibit B-1-1, Appendix D7, p. 17; Exhibit B2-8, BCUC 3.25.1) Thus, it seems that while SQIs will be a matter for discussion at the Annual Review, Fortis views the Mid-Term Review as the appropriate time to determine whether a serious problem or degradation of service exists.

Fortis has outlined no specific process for dealing with a degradation of SQI results. It takes the position that if there has been a serious unaddressed degradation in results that remains unaddressed, the Commission can explore potential off-ramps. Fortis describes the "off-ramp provision" as contemplating a complete regulatory review of the PBR Plan. This would be triggered only if there was "sustained serious degradation of the SQIs." (Exhibit B2-8, BCUC 3.25.2) This is in contrast to previous PBRs where the SQIs were reviewed annually and interveners had some level of input as to the level of earnings share if SQI benchmarks were not met.

Fortis' position on penalties or rewards is that given Fortis' lack of control, they should not be linked to SQI performance relative to their benchmarks. As an example, Fortis notes that "colder than normal weather coupled with higher gas costs can increase call centre volume dramatically and result in a one-time reduction in SQI beyond the reasonable control of the Company." In such instances, it should not necessarily be rewarded or penalized. Fortis acknowledges that one of the themes throughout the proceeding is that the Commission should be concerned that Fortis' SQI proposal lacks enforceable consequences. It points to its ongoing history with the management of SQIs as support for its current proposal. It also states that its witnesses have consistently voiced their commitment to managing the business in a manner that maintains existing service levels. (Fortis PBR Final Argument, pp. 151–152; Exhibit B2-11 CEC 3.40.1; Exhibit B2-8, BCUC 3.25.3)

Intervener Submissions

CEC submits that in the event of performance failures without adequate explanations, it is appropriate to enforce consequences. It also notes the lack of a definition for a serious service degradation and cites the AUC Decision[14] which developed a consultation process as a means of setting performance measures within PBR. CEC sees this as "an appropriate method of ensuring that the most important performance metrics are established and included as criteria for incentive payments." CEC believes the Fortis proposal leaves too much ground between the degradation of service and the move toward off-ramps. If service is degraded, the Commission is placed in the position of either accepting the results of degraded service or having to reconsider the entire regulatory process. CEC recommends that where targets are missed, the utility be subject to

[14] Exhibit B-1-1, Appendix D8, pp. 91, 881-883.

Commission examination during the Annual Review with a determination of appropriate consequences. (CEC PBR Final Argument, pp. 210–212)

ICG considers the purpose of SQIs is to ensure the utility does not sacrifice service quality during a PBR. However, its position is that SQIs are "not sufficiently sensitive, with too many confounding factors, for service quality indicators to detect any changes to either O&M activities or capital investments during a PBR Plan." ICG argues that while reliability indicators like System Average Interruption Duration Index (SAIDI) or System Average Interruption Frequency Index (SAIFI) can change over time if maintenance activities or investments in infrastructure change, year-to-year changes are more affected by weather than any other factor. Consequently, ICG does not consider the professed purpose of SQIs to be achievable. (ICG Final Argument, pp. 35–36)

BCPSO notes that in the previous PBR, SQI results were reviewed annually and participants were able to make submissions with regard to whether a deviation from a benchmark was sufficient to warrant a limiting of incentive payments to the utility. Its view is that this approach should be taken in the current PBR plan as it falls short of cancelling the PBR in its entirety yet recognizes that customers suffer from a drop in service quality and should be compensated. (BCPSO PBR Final Argument, para. 64)

COPE states that at the "heart of the problem with the Companies' Service Quality Indicators proposal is that the way it approaches the *service* side of the [regulatory] compact is not consistent with its approach to the financial *performance and reward* side. It adopts a mechanism of financial risks and rewards to boost the financial performance of the utilities, but rejects that approach to service performance." (COPE Final Argument, p. 6)

COPE's expert witness, Ms. Alexander provides substantial commentary on the application of penalties for sub-standard performance on SQI's and recommends a program be put in place. These are also referred to as "compensation credits" designed to compensate the customer who has suffered the poor service quality (T5:875). Ms. Alexander was able to provide numerous examples in other jurisdictions where such penalty schemes are in place. (FEI Exhibit C2-13, BCUC 1.14.2)

In Final Argument, COPE muses that the use of the word "penalty" was unfortunate in that it was not an accurate reflection of Ms. Alexander's concept, which was compensatory in nature and not really punitive. In spite of extolling the virtues of the approach recommended by its witness, COPE stops short of specifically advocating that the Commission consider implementation of a penalty based regimen. In its conclusions COPE states that it agrees emphatically with the Fortis statement made in Final Argument:

> "In the event that the Commission considers the proposed PBR Plan and the existing statutory mechanisms to be insufficient, and considers it necessary to incorporate a term into the PBR Plan that makes earnings sharing conditional upon maintaining service quality, the Commission should proceed with caution to ensure that the PBR Plan remains compliant with the UCA and fair to the Company as well as rate payers"
> (FEI PBR Final Argument, p. 161)

COPE's concern is that the PBR is slanted toward the utilities and a reinforcement of the customer service side of the regulatory compact is needed. It views the SQI component of the PBR proposal as seriously deficient and asserts there is a need for mechanisms to ensure sufficiently robust service standards that will inhibit any incentive the utility may have to cut corners. To this end COPE states that "SQI's must be meaningful, they must be measurable, and they must have teeth" recommending the Commission develop an effective mechanism to rebalance PBR incentives to achieve this. (COPE Final Argument, pp. 46–50)

IRG does not support Ms. Alexander's penalty recommendations and recommends the Commission reject them. In IRG's view, the avoidance of penalties would become a distraction for FBC management and staff and not result in any material increases in service quality, reliability or safety. (IRG Final Argument, p. 12)

Fortis Reply

Fortis acknowledges that using Off-Ramps as an enforcement tool for SQIs is a blunt instrument. The Companies see it as a tool of last resort, stating that they have proposed the same service quality trigger that existed in previous PBRs. Related to this, Fortis does not define sustained serious service degradation considering it best to allow the Commission to consider all of the circumstances before a decision is made to terminate the PBR. (Fortis PBR Final Argument, pp. 88–89)

In considering the proposal to limit PBR incentives as a means of enforcing service quality, Fortis makes the following submission:

> "Under section 59 of the UCA, a rate is "unjust" or "unreasonable" if the rate is either "(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility" or (b) insufficient to yield a fair return. The rates under PBR are set based on the utility taking appropriate steps to deliver a particular level of service quality. The rate yielded by the PBR Plan is, in effect, too high if service quality declines materially as a result of some imprudent conduct by the utility. A finding of imprudence is a precondition to disallowing a portion of the incentive because the overall PBR must still confer an opportunity to earn a fair return. The presumption of prudence would apply."

Commission Determination

There does not appear to be consensus among the interveners with respect to the Fortis SQI proposal. CEC, BCPSO and COPE are all in agreement that the Fortis proposal for the handling of SQIs falls well short of optimum and, to be effective, has to include consequences for serious degradation of service. For ICG and IRG the primary concern appears to be access to reliable service and neither supports the introduction of a penalty regimen as a means of achieving this. ICG has also raised concerns as to the effect of confounding factors such as weather on key reliability measures or whether established measures are effective at measuring the impact of changes in maintenance and infrastructure over shorter PBR time periods.

The Commission Panel is in general agreement with CEC, BCPSO and COPE with respect to the need for consequences related to service degradation. The Fortis proposal for the management of SQIs within PBR is much too vague and lacks consequences other than the potential for an off-ramp. The PBR is being approved with incentives for the utility to create efficiencies and reduce unnecessary cost. However, if O&M and maintenance capital are too tightly constrained this may result in a degradation of key service level areas. Therefore, the Panel considers that incentives related to reducing costs and creating efficiencies need to be counterbalanced to ensure this occurs without a degradation of service levels as measured by SQIs. Confounding this somewhat is the point raised by ICG that the short-term actions taken by the utility affect long-term SQI results but may have limited effect on short-term measurements for some SQIs. On the other hand, external factors such as weather may have a significant impact on short-term SQI measurements which dissipate when considered over the longer term. Fortis has acknowledged this latter point by recommending that an assessment of unsatisfactory performance on SQIs should not occur until the mid-term review following year three of PBR. The Panel notes there is no evidence on the record concerning the length of time it takes for an action undertaken by a utility to be reflected in SQI performance. In the Panel's view a drop in performance on a SQI would likely depend on the particular performance measure and the severity of the action or inaction of the utility. Therefore, the Commission Panel is not persuaded there is justification for SQI review to be delayed beyond the next Annual Review.

Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs. The Panel considers that a failure to underline the importance of SQIs sends the wrong message to the utility and invites behaviours which may not support the achievement of safe and reliable service.

The next question is what consequences are most appropriate? The ultimate consequence as proposed by Fortis is to invoke the off-ramp option and cancel the PBR. In the view of the Panel this should remain but in addition there is a need for less drastic alternatives to terminating the PBR. Ms. Alexander has proposed that the Commission institute a penalty regimen with predefined penalties (also referred to as compensation credits) assessed to the utility for failure to meet one or more SQI targets. This option received little support from the intervener group. Another option is to tie the achievement of the full earnings-sharing ratio conditional upon maintaining service quality levels. This approach, which was recommended by BCPSO, addresses a number of the concerns of interveners and creates consequences for failure to achieve satisfactory levels of service quality without going to a penalty based regimen as proposed by Ms. Alexander. This modified approach offers the advantage of linking consequences only to incentive earnings which exceed the Commission approved I-X formula driven ROE returns. Reducing excess earnings to no lower than the approved ROE is not unjust or unreasonable. In addition, because the maintenance of service quality is tied to the earnings sharing mechanism, it will only apply when there are incentive earnings to share. This clearly establishes the achievement of service quality standards as a precondition to the earning of incentives. As a consequence, concern that a utility may be motivated to put the achievement of service standards at risk in order to earn an incentive is, to a degree, mitigated. **Therefore, the Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.**

2.3.3.2 What SQIs are Appropriate?

The issues related to which SQIs are appropriate for this PBR received extensive review within the proceeding. Fortis has proposed a set of SQIs it considers appropriate for the purposes of the PBR. It has also provided a proposal for discontinuing some of the SQIs currently in place. The Fortis proposal and related issues raised by interveners will now be discussed.

<u>Fortis' Proposed SQIs</u>

Table 2.25 outlines the SQIs FEI and FBC have proposed. Fortis has proposed a benchmark as a measure of service quality for many of these.

Table 2.25 Service Quality Indicators (SQIs) Proposed by FEI and FBC

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Emergency response time	Percent of calls responded to within one hour	95%	Percent of calls responded to within two hours	85%
First contact resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone service factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All injury frequency rate	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	--	Informational indicator – 3 year rolling average of lost time injuries plus medical treatment injuries	--
Customer satisfaction index	Informational indicator	--	Informational indicator	--
Public contact with pipelines	Informational Indicator – 3 year rolling average of number of line damages per 1,000 BC One calls received	--	N/A	N/A
System Average Interruption Duration Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIDI (average cumulative customer outage time)	--
System Average Interruption Frequency Index	N/A	N/A	Informational indicator- 3 year rolling average of SAIFI (average customer outages)	--

(Source: FBC Exhibit B-1, p. 69; FEI Exhibit B-1, p. 76)

Discontinued SQIs Proposed by Fortis

As previously noted, Fortis has also proposed to discontinue a number of existing SQIs which they believe are of little value going forward. These include the following:

FEI Discontinued SQIs Proposal

- Transmission Reportable Incidents
- Leaks per Km of Distribution System Mains
- Number of Third Party Distribution System Incidents
- Accuracy of Transportation Meter Measurement First Report
- Number of Customer Complaints to the BCUC
- Percent of Industrial Customer Bills Accurate
- Number of Prior Period Adjustments

(FEI Exhibit B-1-1, Appendix D7, pp. 16–17)

FBC Discontinued SQI Proposal

- Generator Forced Outage Rate
- Residential Connections Completion Time
- Residential Extension Quoting Time
- Residential Extensions Completion Time
- Injury Severity Rate
- Vehicle Incident Rate

(FBC Exhibit B-1-1, Appendix D6, pp. 12, 13)

Intervener Submissions

More generally, CEC takes the position that the SQIs put forward by Fortis do not adequately protect the ratepayer. An example of this is the lack of asset health SQIs which may incent the delay of maintenance activities resulting in undesired consequences. It considers many of the proposed SQIs to be of greater interest to residential customers than to commercial customers noting that FEI has no insight into commercial sector satisfaction given the cancellation of the Large Commercial Customer Satisfaction Survey. (CEC PBR Final Argument, pp. 194–196; pp. 203–204) In assessing SQIs, CEC recommends the Commission consider measures that:

- Provide long-term protection to all ratepayer groups from service degradation or increased expenses;
- Deter cost–cutting in areas that can or could affect service quality and reliability;
- Adequately address all areas of service, especially those that may be likely targets for cost-cutting; and
- Are measurable/quantifiable.

(CEC PBR Final Argument, p. 193)

COPE considers Ms. Alexander's approach to calibration of benchmarks to be reasonable and balanced and urges the Commission to adopt best practices and not rely "on the lowest common denominator in establishing its policies for SQI in the context of a PBR." COPE supports the notion of relying on 3 year averages as a means of controlling service volatility. (COPE PBR Final Argument, pp. 27–30)

Interveners have made the following recommendations with respect to specific SQIs proposed by the Companies in their applications:

(i) Emergency Response Time

FEI proposes to change to the Canadian Gas Association (CGA) definition of an emergency event and the CGA response time calculation. Based on the CGA definition, FEI has, over the 2010 to 2012 period, responded to emergency calls within one hour 97.7 percent of the time. FEI proposes to set its emergency response benchmark at 95 percent, stating that it is approximately equal to the industry average and in the top quartile of CGA members. (FBC Application, Exhibit B-1-1, Appendix D7, pp. 5–6)

CEC and BCPSO recommend that FEI should be required to maintain its emergency response time metric at current levels (97.4 percent) which it has been able to achieve on a consistent basis, rather than setting it at a lower level (95 percent). (CEC PBR Final Argument, p. 215; BCPSO PBR Final Argument, p. 19)

Over the same period FBC has responded to an initial identification of a loss of power, to arrival of FBC staff at the trouble site within two hours or less, 93 percent of the time. FBC states that its current benchmark is 85 percent and represents a level of response expected by its customers. It proposes to maintain the benchmark at this level.

BCPSO submits that the FBC emergency services benchmark should be set at least 90 percent as since 2007 FBC has achieved a level of 91 percent or higher and this is the level that customers have been receiving and has been sustained at current expenditure levels. (BCPSO PBR Final Argument, para. 49, p. 16)

(ii) Meter Exchange Appointment

CEC and BCPSO agree with FEI's proposed 95 percent benchmark. CEC does not support the COPE proposal to replace this metric with a missed appointment customer credit of $25. (CEC PBR Final Argument, pp. 215–216; BCPSO PBR Final Argument, p. 19)

(iii) First Contact Resolution

CEC considers first contact resolution as important to customers, but its usefulness complements other measures (CEC PBR Final Argument, p. 217).

(iv) Telephone Service Factor (emergency)

CEC and BCPSO agree with the proposed benchmark that 95 percent of calls be answered within 30 seconds or less (CEC PBR Final Argument PBR, p. 216; BCPSO PBR Final Argument, p. 19).

(v) Telephone Service Factor (Non-emergency)

CEC submits that the average wait time is not necessarily indicative of the wait time experienced by some customers. CEC recommends the Companies develop an abandonment rate measure and SQI. (CEC PBR Final Argument, pp. 216–217)

Ms. Alexander recommends 80 percent for both FEI and FBC referring to this as the best practice standard. (FEI Exhibit C2-10, p.27) BCPSO had no objection to the proposed Telephone Service metric. (BCPSO PBR Final Argument, p. 19)

(vi) Billing Index and Meter Reading Accuracy

Ms. Alexander recommends that both of these indexes be eliminated for FBC as modern computerized billing systems make billing and meter reading highly accurate and timely. However, the metric should be retained for the gas utility. (FEI Exhibit C2-10, pp.28–31)

CEC disagrees with COPE pointing out the measure allows for the identification of problems. (CEC PBR Final Argument, p. 217)

a) <u>Fortis Discontinued or Informational Only SQIs</u>

Both CEC and COPE have concerns that the Companies have removed any SQIs with benchmarks or targets that are related to reliability. CEC notes that establishing SQIs intended to reflect the experience between the customer and the company are inadequate protection of customer interests pointing out that the interests of ratepayers go far beyond the typical 'customer experience'. CEC list customer interests such as asset health, corporate responsibility, special irrigation concerns or energy efficiency activities as examples of customer interests which are not covered by SQIs. (CEC PBR Final Argument, p. 202) Specific issues related to dropped or Informational Only SQIs are as follows:

(i) SAIDI and SAIFI

FBC proposes to report on the SAIDI and SAIFI service quality indicators on an informational basis only. Fortis suggests that these indicators are not considered to have a significant linkage between costs and results and it may take years for the results to be evident.

CEC believes that whether an indicator responds immediately or not to cost cutting should not exclude its use. In CEC's view, the ratepayer needs protection from long-term degradation in reliability which in its view stems from asset health which can be affected by the level of expenditures on maintenance. (CEC PBR Final Argument PBR, p. 203–205)

COPE submits that FBC's generally acceptable performance for reliability as exhibited by SAIFI and SAIDI would be placed at risk during the PBR period by relegating it to an informational SQI with no performance target. (COPE Final Argument, p. 18)

(ii) All Injury Frequency Rate (AIFR)

Both FEI and FBC propose the use of the AIFR as an informational SQI. COPE argues that the Companies should be held accountable for AIFR results. While recognizing that the Companies cannot control the conduct of all their employees at all times, its expert witness, Ms. Alexander notes "management is in charge of the workplace culture, the safety systems, and the educational activities designed to prevent as many workplace accidents as possible." (COPE Final Argument, p. 40)

(iii) Public Contact with Pipelines

FEI has introduced the public contact with pipelines SQI to reflect the importance of educating the public on the risk associated with pipeline contact. The SQI is a "measure of the overall effectiveness of the public's awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers." FEI proposes that this SQI be an informational measure with no benchmark. (FEI Application, Exhibit B-1-1, Appendix D7, pp. 12–13)

COPE argues that this is an important measure related directly to public safety and FEI should conduct itself in a way which mitigates risks and be held accountable for the results (COPE Final Argument, p. 38).

Fortis Reply

Fortis considers it appropriate that it has relied on a suite of SQI's that focus on the direct customer experience noting that the interveners seek to include additional performance indicators concerning a variety of matters including asset health and corporate responsibility. Fortis acknowledges that these matters may be of interest to customers but argues that it does not necessarily follow that SQIs related to these matters should be covered under the PBR plan. In support of its approach, Fortis notes that the Companies do not have the discretion to allow assets to deteriorate and they already report to the Commission in considerable detail in a more useful format (citing comments from T6:1196 with reference to metrics on the state of the assets and the reporting regimen through the Oil and Gas Commission).

Fortis argues that its current level of service is high and

> "[i]ncreasing service level requirements above the benchmarks proposed by FortisBC will give rise to asymmetric risk in circumstances where there is no direct correlation between utility spending and service levels." In other words, the odds are higher of missing a high benchmark metric as compared to a lower one unless it can be determined that additional expenditures can produce the desired results. It explains that it has set a reduced benchmark of 95 percent in the case of Emergency Response times because "the odds of falling below the benchmark of 97.6% for reasons beyond utility control are significantly higher than would be the case with a benchmark set at 95%." (Fortis PBR Reply, p. 84)

Commission Determination

There are two key issues that the Commission Panel must address. The first of these is concerned with whether the SQI's proposed by Fortis are appropriate. If not, what SQIs should be added? Related to this is whether the informational indicators as proposed, should be so categorized or whether some of these should be upgraded to full SQIs with performance benchmarks. The second issue deals with the level of the performance benchmarks.

Are Fortis' Proposed SQIs Appropriate?

Under the *Utilities Commission Act* the Commission has an obligation to ensure the utility is supplying "reasonable, safe, adequate and fair service" (s. 25). Reasonable, safe and adequate service entails providing services that are reliable, responsive to consumer needs and protective of the safety of the public which includes both ratepayers and employees of the Utilities. The Commission Panel considers Fortis' contention that SQIs should be focused on the customer experience as being too narrow in scope. In our view, the SQIs are a mechanism to assist the Commission to ascertain whether the Companies are living up to the obligations envisaged in the regulatory compact and legislated under the UCA.

The proposed benchmarked SQIs are focused primarily on the areas of direct interaction between the Companies and customers and don't fully reflect all of its service obligations. **Therefore, the Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.** All of these are required to enable the Commission to evaluate whether the Companies are meeting obligations under the UCA.

The Commission Panel notes that only two of the benchmarked SQIs proposed by FEI relate to safety (Emergency Response Time and Telephone Response – Emergency) and only one FBC SQI is safety related (Emergency Response Time). The remaining benchmarked SQIs, five in the case of FEI and four for FBC relate to customer/company interactions. Further, FEI has no service quality indicators dealing with reliability of service while FBC has only two, SAIFI and SAIDI, both of which are proposed as informational indicators. In our view, this does not reflect a balanced approach.

A concern has been raised by many interveners with respect to the elimination or a move to informational status of reliability related SQIs. Given the length of term of the PBR, the Panel agrees and is equally concerned that there are no SQIs with established performance targets to address reliability. Moreover, in our view, the lack of SQIs fails to meet the Commission's need to assure itself that service quality, as required by legislation, is being met.

The Commission Panel has separated SQIs into three categories: Safety, Customer Needs and Reliability. **Within these categories the Commission Panel approves the following SQIs proposed by Fortis:**

- **Safety**
    - **Emergency Response Time**
    - **Telephone Service Factor (emergency)**
- **Customer needs**
    - **First Contact Resolution**
    - **Billing Index**
    - **Meter Reading Accuracy**
    - **Telephone Service Factor (non-emergency)**
    - **Meter Exchange Appointment**

In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include:

- **Safety**
    - **All Injury Frequency Rate**
    - **Public Contact with Pipelines**
- **Reliability**
    - **SAIDI (weather normalized) FBC only**
    - **SAIFI (weather normalized) FBC only**

Further, the Panel approves the following informational indicators:

- **Customer Satisfaction Index**
- **Telephone Abandon Rate**

and we direct Fortis to reinitiate the following informational indicators:

- **Generator Forced Outage Rate**
- **Transmission Reportable Incidents**
- **Leaks per KM of Distribution System Mains**

Telephone Abandon Rate, while reported by Fortis to be very low (T6:1275), has not been reported previously. The Panel considers this a useful measure in determining the level of service failure which is important given the Fortis proposal to lower its Telephone Service Factor SQI benchmark metric. The Panel has also directed Fortis to reinstate Generator Forced Outage Rate, Transmission Reportable Incidents and Leaks per KM of Distribution System Mains as informational indicators. While the Panel accepts the FBC argument that it has a portfolio of resources to draw upon if a generator fails, we note that a generation failure might impact power purchases thereby having an impact on rates. Because of this, it remains a valuable indicator. Likewise the Panel considers Transmission Reportable Incidents a valuable informational indicator as it tracks the number of reportable incidents to outside agencies such as the BC Oil and Gas Commission and WorkSafe BC.

With respect to the proposed SQIs which have been approved, the Panel notes the position of Fortis that the Billing Index and Meter Reading accuracy may not be needed due to their consistently positive results, and agrees with Fortis' assessment of the value to customers. However, we recommend that this be revisited at some future Annual Review during the PBR.

The Panel has changed a number of informational indicators to benchmarked SQIs. Under Safety, AIFR and Public Contact with Pipelines have been added. In the view of the Panel both of these measures reflect important safety concerns. The Panel agrees with COPE that while the Companies cannot control the actions of their employees, they are accountable for them, and as such, are responsible to take steps to mitigate any harmful behaviour. Therefore, this is an appropriate SQI metric which should be benchmarked and managed. The Panel has a similar view with Public Contact with Pipelines. As pointed out, performance on this SQI is a reflection of public awareness and while the public cannot be controlled, FEI can heavily influence performance on this SQI through the activities it undertakes to create awareness.

Under Reliability, the Panel has added SAIDI and SAIFI as benchmarked SQIs for FBC. We agree with COPE's and CEC's arguments that the ratepayer should not be placed at risk over the PBR period by relegating this to an informational indicator. This SQI goes to the heart of concerns raised by interveners with respect to underspending of capital. While the Panel acknowledges that both of these measures have to be viewed over the longer term and may be more affected by weather in the short term, we consider them valuable as indicators of utility performance.

Level of Performance Benchmarks

With regard to existing SQIs, Fortis proposes changes to two performance benchmarks. FEI proposes that Emergency Response Time be reduced from its average performance level over the 2010 to 2012 period of 97.7 percent to a slightly reduced performance benchmark of 95 percent. **The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1, Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further direct that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period.** The Panel acknowledges the concerns raised by Fortis with respect to the odds of falling below this level. This concern is dealt with in Section 2.3.3.3 where the introduction of "satisfactory performance ranges" is addressed.

A second change recommended by Fortis is related to FEI's non-emergency Telephone Service Factor. Fortis proposes to reduce the percentage of calls answered in 30 seconds to 70 percent from 75 percent. **The Commission Panel approves the reduction to 70 percent.** Although there is evidence that the industry standard is 80 percent, the Panel grants this approval for two reasons:

- Fortis reports a very low abandon rate in the 2 percent range for both FEI and FBC.
- FEI has implemented the call-back capability of its new system with substantial uptake. This mitigates to an extent the impact of unreasonable wait times.

In consideration of these factors, the Panel is persuaded that customer needs are being met. In addition, the Panel has ordered that in the future Fortis track phone call abandon rate as an informational indicator. If there is an increase in abandon rates the Commission may revisit telephone service SQIs in the future. **The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.** The Panel notes that all of these are sufficiently high to be reasonable or reflect an average of recent performance levels.

For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark. This methodology will be addressed further in Section 2.3.3.3.

A summary of these determinations and performance benchmarks are included in Table 2.26. **The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.**

Table 2.26 Approved Service Quality Indicators (SQIs)

Performance Measure	FEI Indicator	FEI Benchmark	FBC Indicator	FBC Benchmark
Safety SQIs				
Emergency Response Time[3,5]	Percent of calls responded to within one hour	97.7%	Percent of calls responded to within two hours	93%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%	N/A	N/A
All Injury frequency rate[1,5]	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	2.08	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	1.64
Public contact with pipelines[1,5]	3 year average of number of line damages per 1,000 BC One calls received	16	N/A	N/A
Responsiveness to Customer Needs SQIs				
First Contact Resolution	Percent of customers who achieved call resolution in one call	78%	Percent of customers who achieved call resolution in one call	78%
Billing Index	Measure of customer bills produced meeting performance criteria	5	Measure of customer bills produced meeting performance criteria	5
Meter Reading Accuracy	Number of scheduled meters that were read	95%	Number of scheduled meters that were read	97%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%	Percent of calls answered within 30 seconds or less	70%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	95%	N/A	N/A
Customer Satisfaction Index	Informational indicator	--	Informational indicator	--
Reliability SQIs				
System Average Interruption Duration Index – Normalized[1,5]	N/A	N/A	3 year average of SAIDI (average cumulative customer outage time)	2.22
System Average Interruption Frequency Index – Normalized[1,5]	N/A	N/A	3 year average of SAIFI (average customer outages)	1.64
Generator Forced Outage Rate[2]	N/A	N/A	Informational indicator.	--
Transmission Reportable Incidents[2]	Informational indicator – Number of reportable incidents to outside agencies	--	N/A	
Leaks per KM of Distribution System Mains[2]	Informational indicator	--	N/A	

[1]Changed from an informational indicator to a benchmarked indicator
[2]Added as informational Indicator
[3]Benchmark changed
[4]Added benchmarked SQI
[5]Benchmark calculated as the average over the 2010, 2011 and 2012 period

2.3.3.3 Process to Review and Manage SQIs

The first issue the Panel must consider is whether holding the Companies to firm performance benchmarks is a reasonable approach to manage SQIs in a PBR context. Once this has been determined, the next issue is how best to implement a process to tie consequences to the failure to achieve reasonable performance on SQIs.

FEI explains that in establishing the SQI benchmarks it has relied on the Company's performance over recent years or on general industry standards. (FEI Exhibit B-1-1, Appendix D7,p. 2). It believes it is appropriate to base the proposed benchmarks on performance in recent years because the benchmarks are then reflective of the costs required to provide the service levels. (FEI Exhibit B-6, BCPSO 1.26.1) The use of a rolling average acts to smooth out annual results providing for a longer term indicator of any trends that may be developing. (FEI Exhibit B-6, BCPSO 1.26.1; FBC Exhibit B-7, BCUC 1.60.1.1)

As noted earlier, COPE has taken the position that the best way to determine SQIs and reduce volatility in results is to rely on a three year average for determining performance benchmarks for SQIs. Fortis has responded by pointing out that a drawback to relying upon an average is that actual amounts will fall above and below the average. Thus, what might be interpreted as a decline in service may not be reflective of what is occurring. (Fortis PBR Reply pp. 82–83)

Fortis has noted that in using a three-year average to set the SQI benchmark, by definition there will be years within the average that are below the average. For these reasons the Companies do not see the merit of tying specific consequences to the SQI benchmark targets. (Fortis PBR Reply, pp. 82–83)

Commission Determination

The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.** The achievement of performance metrics that fall within this range is acceptable. Performance outside of this range would be unacceptable representing a serious degradation of service which would be subject to consequences. Performance benchmarks would continue to be determined which would serve as a target only and failure to reach them would not have consequences.

Determining the Performance Benchmarks and an Acceptable Performance Range

While the Panel agrees with Fortis that a three-year average helps to smooth out annual results, we do not agree with the use of a rolling average. Use of a rolling average is inconsistent with the concept of a satisfactory performance range as it could perpetuate a downward trend. The Panel agrees with BPCSO that setting the benchmark based on the last three-year period for which annual data was available (2010, 2011 and 2012) establishes the benchmark at a level that is reflective of the costs required to provide this level of service. The Panel has previously approved a performance range which provides for normal annual variability. **The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.** Once set, these will serve as performance benchmarks for the balance of the PBR.

The Commission Panel has considered options for setting an acceptable performance range for SQI metrics. In our view this is not simply a matter of setting a plus or minus percentage range that would be applied to all SQIs. Rather, a variety of factors like the economy, weather and the potential for variation must be considered in determining the range**. For this reason, the Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.** An appropriate time to deal with this is in the period leading to the first Annual Review. Consultation among the parties should form a part of the process with recommendations flowing from it. **In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.**

In establishing the performance range for SQIs, the Panel expects the Companies and the stakeholders to take into consideration the following factors:

- The variance that has been experienced in the benchmark historically;
- The historic trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

Failure to Meet SQI Benchmarks

Where one or more of FEI or FBC's SQI performance metrics are outside the established range, the matter will be handled as part of the Annual Review. **Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.**

Where, after due process, the Commission finds that Fortis has failed to provide adequate service and the failure was, in whole or in part, due to the actions (or inactions) of Fortis, the Commission may reduce the share of earnings above the allowed rate of return that would otherwise flow to the Company. The reduced share of earnings would be credited to customers in the form of a compensation credit. **The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.**

When assessing the magnitude of any reduction in each Company's share of the incentive earnings, the Commission will take into account the following factors:

- Any economic gain made by each Company in allowing service levels to deteriorate;
- The impact on the delivery of safe, reliable and adequate service;
- Whether the impact is seen to be transitory or of a sustained nature; and
- Whether each Company has taken measures to ameliorate the deterioration in service.

Where there are no incentive earnings to share (i.e. the rate of return achieved by the Companies are at or below the approved rate of return), the Commission may still assess whether the level of service provided by the Company is adequate. In this case, the actions taken will be driven by the provisions in the UCA. This might include ordering Fortis, under section 25 of the UCA, to take certain actions to remedy a service deficiency or the imposition of an administrative penalty under section 109.2 of the UCA.

2.3.4 Off-Ramps

Off-ramps are described in the Companies' Applications as "a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances" (FBC Exhibit B-1 pp. 69–70; FEI Exhibit B-1 p. 77). This section addresses off-ramps that could lead to a broader review of the entire PBR Plan and potentially to a termination of the PBR Plan altogether.

There are two off-ramp triggers proposed, a financial trigger and a non-financial trigger. The financial trigger is engaged when the post-sharing earnings of the Company exceeds or drops below the allowed ROE by 200 basis points. Given the 50:50 earnings sharing mechanism, this means that actual earnings would have to be above or below the approved ROE by 400 basis points to trigger a review of the PBR Plan. Fortis states that the allowed variance between the actual and approved ROE before the off ramp is triggered must be large enough to incent the Companies to pursue efficiencies while at the same time be limited enough to safeguard against potential excessive profits or losses. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

Fortis proposes that the non-financial trigger would be engaged if the Companies' service levels fell to an unacceptable level. In the Companies' view, only a "sustained serious degradation of the SQIs" would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet an SQI(s) must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 78)

2.3.4.1 Financial Trigger

Previous Fortis PBR Plans in British Columbia

Neither of the earlier PBR plans of FEI or FBC included a firm quantitative reopener or off-ramp. However FEI and FBC, as part of the Annual Review process had the right to request a change or termination of the PBR Plan if there were unacceptable outcomes associated with it.

B&V states: "[t]his provision does not represent the best approach to addressing serious issues with a PBR plan." However, B&V sees the provision as "understandable" within a negotiated settlement that includes a number of other provisions. (FEI and FBC Exhibit B-1-1, Appendix D1, pp. 46–47)

The 2004 FEI PBR Plan had a trigger of +/- 150 basis points around the approved ROE (after earnings sharing) but this was not considered an automatic off-ramp. It was open for parties to request a Commission review of the 2004 Plan if the threshold was exceeded. The 2007 FBC PBR Plan had a trigger mechanism of +/- 200 basis points around the approved ROE but this was not an off-ramp. If the earnings threshold was exceeded, the earnings variance (positive or negative) would be placed in a deferral account for review and disposition at the next Annual Review. (Fortis PBR Final Argument, p. 56)

In the previous PBR period, the Companies exceeded their allowed rate of return by a maximum of 145 basis point (FEI) and by 115 basis points (FBC) (Exhibit B2-11, CEC 45.4). Considering its previous PBR plan, FBC states: “FBC’s going-in rates for this PBR Plan already incorporate substantial productivity savings achieved through the 2007-2011 PBR period, and those that have been realized in the 2012-2013 period through a renewed productivity focus. As a result, it will be challenging for this PBR Plan to produce the same level of savings that were realized under the 2007 Plan.” (FBC Exhibit B-1, p. 5)

Intervener Submissions

CEC submits that the +/- 200 basis point differential post-sharing is too high. CEC notes this is equivalent to a +/- 400 basis point variance if there were no earnings sharing mechanism and is 50 basis points higher than the previous FEI PBR plan. CEC states that there is “little justification for either the number itself or for an increase.” The proposed financial trigger is viewed by CEC as relatively high in comparison to other jurisdictions where the trigger is +/- 300 basis points with no earnings sharing mechanism. (CEC PBR Final Argument, pp. 165–166)

CEC recommends that the financial off-ramp should be set at the level of +/- 150 basis points (CEC PBR Final Argument, p. 171). CEC further advocates the use of a multi-pronged trigger to better protect customer interests if a PBR plan is approved (CEC PBR Final Argument, pp.167–168).

CEC also contends that the financial trigger is asymmetric in that Fortis, regardless of the PBR trigger, has the ability to file a cost of service application at any time if its actual rate of return falls too far below the allowed return. CEC does not see the consumer having the same redress if actual

ROE is consistently significantly above the allowed ROE but below the trigger. CEC further asserts that Fortis could moderate or apply a cap to its earnings to avoid triggering an off-ramp.

Fortis refutes the suggestion that the off-ramp is asymmetric. Fortis submits that customers have the same opportunities afforded by an off-ramp as the Companies. Fortis may address financial distress through an application to the Commission while customers may use an equivalent mechanism of filing a complaint to the Commission. In addition, Fortis states there is nothing in the PBR Plan "that would (i) purport to unlawfully fetter the Commission's discretion in the future, or (ii) skirt the rule against retroactive ratemaking." (Fortis PBR Reply, pp. 52–53)

Fortis also refutes the concept of a multi-prong trigger. In response to a CEC information request, stating it would not support a two-year trigger concept because:

- Dual trigger points are more prone to controversy for potential gaming concerns. (i.e. by increasing expenditures in one year to lower the actual ROE to compensate for a high ROE achieved in a previous year); and
- Fortis intends to pursue efficiencies and savings on a consistent basis throughout the PBR term. In Fortis' view this means that if the two-year trigger was set significantly below the single year trigger, there is a high likelihood that if one year's results were above the two-year trigger level, the subsequent year likely would be as well. This would trigger the off-ramp to the detriment of achieving longer-term benefits under the plan. (Exhibit B2-11, Fortis CEC 3.45.3, pp. 114–115)

Fortis submits that CEC has provided no rationale to explain why a multi-prong trigger point is more appropriate than a single trigger point. (Fortis PBR Reply, p. 53)

ICG supported the off-ramp elements of the Fortis application (ICG PBR Final Argument, p. 25). No other interveners addressed the financial trigger in the off-ramp.

Commission Determination

The Commission Panel views the triggering of an off-ramp as setting in motion a two-stage process. The first stage consists of a process before the Commission to assess potential remedies to the situation, including the potential for amending or re-calibrating the PBR plan to allow it to continue. A second stage to the process would be triggered if satisfactory solutions could not be found through modification of the PBR plan. This stage would deal with how to exit from the plan. This could include a variety of options from going back to a cost of service methodology to a redesign of the PBR.

With respect to the financial trigger, the Commission Panel agrees with Fortis that it should strike a balance between being high enough to incent the utility to vigorously pursue efficiencies and savings while being low enough to provide a safeguard for customers and the utility if either profits or losses become excessive. The applied for +/- 200 basis points post-sharing means that the achieved ROE before the earnings sharing is calculated would be +/- 400 basis points. This compares to the one year trigger point set in Alberta at +/- 500 basis points (with no revenue sharing) and the OEB trigger point of +/- 300 basis points, both of which are criticized by Fortis' consultant as being too broad. The AUC tempered its one-year trigger by also imposing a two-year trigger of +/- 300 basis points. The Panel notes that Fortis' expert witness testified that "I'm not aware that any utility would get to the point of being 200 basis points below their allowed return without filing a cost of service application" (T4:791).

In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year varies from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years the off-ramp will be triggered.

The Panel is of the view that a 50 basis point differential is in all likelihood not significant enough to give rise to Fortis' concern regarding multi-year triggers being "significantly below" single year triggers.

Regarding intervener concerns that the single-year trigger is too high, the Panel notes that even with substantial productivity savings, Fortis did not exceed their allowed rate of return in their previous PBR periods. The Panel is of the view that the trigger points approved in this Decision will not stifle efficiency efforts and will provide an appropriate balance of protection for the Companies and the ratepayers.

2.3.4.2 Non-Financial Trigger

Fortis proposes that the non-financial trigger would be engaged if service levels fell to an unacceptable level. In the Companies' view only a "sustained serious degradation" of service quality, as measured by the SQIs, would warrant a review of the PBR plan. Fortis does not see the failure to meet one (or more) of the SQI benchmarks as necessarily constituting unacceptable performance. Fortis maintains that assessment of the failure to meet one or more SQIs must take into account variance in performance that occurs due to random events or events beyond the full control of the Companies. (FBC Exhibit B-1, p. 71; FEI Exhibit B-1, p. 2)

Fortis also submits that there are less drastic options to deal with declining service levels, noting that SQIs will be reviewed at each Annual Review. If appropriate, the Companies will work cooperatively with the interveners and the Commission to address any performance deficiencies. (Fortis PBR Final Argument, p. 58)

Fortis further submits that in the event there is a finding that some action of Fortis directly caused or contributed to a decline in service quality, the Commission has options under the UCA that include:

- Ordering Fortis to take certain steps to address service quality; and
- The power to levy administrative penalties after a hearing if the Companies breach the Commission order.

(Fortis PBR Final Argument, p. 155)

Intervener Submissions

CEC raises a number of concerns with respect to the non-financial trigger and submits that:

- the non-financial triggers act as a 'framework for determining whether there is need for a complete regulatory review of the PBR plan' rather than as an off-ramp under which a complete regulatory review of the PBR would be undertaken;
- there is no obligation to maintain specific benchmarks;
- the term "sustained serious degradation" is extremely vague and open to interpretation and debate and should be defined by the Commission.

CEC agrees that the off-ramp should not be triggered if the issue is not caused by the Companies' actions. CEC recommends that the definition of when the off-ramp is triggered should encompass the concept of "prudent Utility management." (CEC PBR Final Argument, pp. 168–169)

BCPSO notes that in the 2004 PBR there was an option for participants in the Annual Review to make submissions to limit incentive payments to the Company if a deviation from an SQI Benchmark was significant. BCPSO recommends that this option be included in the current PBR plan. (BCPSO PBR Final Argument, p. 20)

COPE submits that:

- The Applications and evidence are "bereft of any guidance" as to the definition of a "sustained serious degradation of service quality" (COPE Final Argument, p. 7);
- A review as to whether there was a serious degradation in service quality would not occur until the Mid-term Review. This, in COPE's view would make it "difficult, if not impossible" for the off-ramp to be executed before the final days of the PBR (COPE Final Argument, p. 9);
- Fortis intends the off-ramp to be triggered only if there is a consensus it should be. This, in COPE's view, makes the off-ramp meaningless (COPE Final Argument, p. 10); and
- Even if it is determined that there is a serious sustained degradation of the SQIs, and the off-ramp provision is executed this would still not result in an adjustment to the financial results achieved. (COPE Final Argument, p. 13)

ICG supports the off ramp provisions of the FBC Application (ICG Final Argument, p. 25). Other interveners did not comment specifically on the merits of the non-financial trigger.

Commission Determination

Definition of "Sustained Serious Degradation"

Several interveners have raised concerns with respect to the lack of definition as to what encompasses a sustained serious degradation of service that would warrant the triggering of a review of the complete PBR plan and potentially the termination of the plan. Fortis, by stating that the Mid-Term Review would be the earliest time one could assess whether serious degradation has occurred, implies that "sustained" means degradation is ongoing over two or more years. The concept of what constitutes "serious" degradation is even more vague, with Fortis stating that failure to meet one or more benchmarks does not necessarily constitute unacceptable performance, particularly where under normal conditions there are circumstances that impact the SQI that are outside the Companies' control. (Fortis PBR Final Argument, p. 58)

The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical. The determination of a sustained serious degradation entails judgments that can only be made based on the specifics of the circumstances that have given rise to the purported degradation. The Panel recommends the following criteria as the basis of the assessment of whether "sustained serious degradation" has occurred:

- Has the degradation persisted for two or more years and can it be reasonably anticipated to occur in the future?
- Has Fortis undertaken actions that are expected to mitigate the deficiency?
- Is the degradation due to random events that are not expected to recur?
- If the events impacting the SQI also are affecting other utilities, are the other utilities experiencing the same degradation of service quality?

In Section 2.3.3.3 the Panel sets out the consequences if Fortis fails to provide adequate safe and reliable service. We have also added additional SQIs to those proposed and amended some of the filed SQIs. We are of the view that this provides adequate incentive to the Companies to maintain appropriate service levels. This should render less likely the occurrence of "sustained serious degradation" of service quality.

Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate. In particular, parties are requested to bring recommendations forward to the Commission where there have been a "sustained serious degradation" of service.

2.3.5 Capital Expenditures – What's In What's Out

2.3.5.1 Introduction

Fortis proposes to include only a portion of its capital spending in its formulaic capital spending envelope. This gives rise to a number of issues, including:

1. What is the appropriate base capital upon which to base the formula?
2. What proportion of capital spending should be included? What, if any, capital projects should be excluded from the formula?
3. How can capital expenditures, which are often lumpy, be appropriately matched to a much less lumpy formula driven spending envelope?
4. How can the ratepayer be protected from chronic underspending relative to the formula driven spending envelope?
5. How can Fortis be protected in the event that necessary capital expenditures drive the actual capital expenditures above the formula driven spending envelope?

The Panel will review these issues in the following sections. First we will review the approach that Fortis is proposing and how capital has been treated in previous Fortis PBR plans. We will also review the AUC's approach to PBR capital as it has been widely discussed in this proceeding.

The Panel considers the issue of the base capital in Section 3.1.3 of this Decision.

2.3.5.2 Treatment of Capital during Previous PBR Periods

Prior to 2004, PBR plans for FBC covered only O&M. All capital spending was approved separately. For FEI, in the PBR plan in effect from 2005 to 2009, "capital expenditures were escalated by a formula that incorporated forecast inflation and productivity factors. It included a 50/50 earnings sharing mechanism between customers and shareholders." FEI further states that "[e]ach year, the capital expenditure forecasts were developed using the customer additions forecast for growth capital and the forecast average number of customers for all other base capital. The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth." FEI adds that CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes. (FEI Exhibit B-1, pp. 34–35)

FEI states that there were "significant capital savings" achieved over the term of its PBR period and that benefits to ratepayers included:

1. Reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Rebasing of the savings in the opening rate base and future rates after the PBR ended.

FEI further describes the capital expenditures:

> "During the 2004 PBR, FEI's actual base capital expenditures for the six-year period were $490.million. This was $80.1 million, or about 14 percent on average, below the formula- allowed capital expenditures of $570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in

> Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI's actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately \$1 million above the formula-based amount." (FEI Exhibit B-1, p.38)

CEC submits that FEI capital underspending during the previous PBR period shows a total of about \$80 million with the annual amounts showing about \$9 million in the 2008 to 2009 period. The aggregate benefit from underspending the capital formula was approximately \$50 million of which the Company received half or \$25 million. This benefit grows and accumulates annually until rebased at the end of the PBR period. Rebasing earlier when the PBR period expired and not extending the PBR process would have saved customers approximately half of the capital payment to the Utility.

It further submits that "[t]his is an example of the failure to understand PBR processes properly. CEC had such a misunderstanding when it participated in extending the previous PBR term and failing to rebase the formula as quickly as possible. CEC has had the advantage of this regulatory process to learn just how poorly PBR incentives are aligned with customer interests. CEC submits that the Commission should ensure that such an error does not happen again." (CEC PBR Final Argument, pp. 90–91)

2.3.5.3 Fortis' Proposal

The formula proposed by FBC for all capital and by FEI for sustainment and other capital is:

$$C_t = C_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *C=Capital Expenditures subject to formula*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

and for FEI's growth capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: *GC = Growth Capital*
SLA = Service Line Additions
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The Panel has reviewed the growth terms for the above formulas in Section 2.2.6 of this decision. In addition, the I- and X-Factors were reviewed in Sections 2.2.2 and 2.2.3, respectively. The Panel will not comment further on the formulas themselves, but will now review the size and nature of capital projects to which the formulas apply along with the consequences of underspending and overspending relative to the formula.

2.3.5.4 CPCN Capital

Fortis proposes separate ratemaking treatments for CPCN projects. CPCN expenditures will be excluded from the formula and will continue to be subject to the existing criteria for determining the need for a CPCN application. It states that "[m]ajor capital project expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service." (FBC Exhibit B-1, p. 55)

For FEI, all projects in excess of $5 million require a CPCN. For FBC, a CPCN is required for projects in excess of $20 million and any other projects: 1) likely to generate significant public concerns; or 2) that FBC or the Commission wishes to handle through a CPCN; or 3) that a credible majority of stakeholders believes should involve a CPCN. (FEI Exhibit B-1, p. 250; FBC Exhibit B-1, p. 226)

Fortis states that "[t]here is no practical way to capture CPCN capital projects under the PBR Plan." In its view, "[t]he nature of capital expenditures is such that the controllable and generally planned investments are included in the plan while other capital should be outside the plan." Fortis also states that Enbridge has proposed a similar customized PBR Plan with separate capital updates for the later years of the plan. (FEI Exhibit B-11, BCUC 1.10.2.; FBC Exhibit B-7, BCUC 1.19.2)

B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It states that it is akin to the adoption of a capital tracker, which is incorporated in PBR plans elsewhere. (FBC Exhibit B-1, p. 55) Fortis submits that "The AUC has been approving significant capital trackers, which are similar in nature to FortisBC CPCNs." (Fortis PBR Final Argument, p. 48)

PEG agrees that the Fortis proposal is tantamount to a tracker treatment for CPCN costs. However, in its view, the eligibility requirements are unusual and incentives to contain the cost of capex for these projects are a concern. Dr. Lowry states that "[i]f you would have a more conventional CAPEX tracker or at least raise the materiality threshold, the problem would — most of the problem would go away." (FBC, Exhibit C1-22, BCUC-IR2, 2.7.2; T7:1487)

With regard to FBC's proposed base capital formula driven spending envelope, ICG submits that "[t]he replacement of detailed project by project analysis of the past with a formula based approach should not be expected to provide better capital expenditure targets. It is more likely that such a change will result in excess returns not related to efficiency gains." (ICG Final Argument, p. 19)

2.3.5.5 Fortis' Proposed Dead-Band

Fortis states that "limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%" (FEI Exhibit B-1, p. 8; FBC Exhibit B-1, p. 40).

To this, BCSPO points out that "the proposed deadband does not take into account the fact that capital is cumulative and that, if there is a consistent under spending of 9.5% per year, this will result in capital expenditures that are 46% lower than one year's capital. As such, in addition to the annual threshold of 10% for capital rebasing, BCPSO submits there should be a cumulative threshold that reflects the cumulative nature of capital." (BCSPO PBR Final Argument, p. 10)

2.3.5.6 Fortis' Expected Capital Expenditures during PBR

2.3.5.6.1 FEI's Capital Spending

FEI estimates approximately $672 million to $689 million of proposed formula driven capital expenditures over the PBR period. FEI believes this allowed capital under PBR provides suitable incentive to find efficiencies for capital expenditures without raising concerns of compromising safe, reliable natural gas service or service quality. (Exhibit B-11, BCUC 1.10.3)

FEI lists the following CPCN projects that will be excluded from the capital formula:

1. The Huntingdon Station Bypass. Loss of functionality of certain sections of the Huntingdon Station can lead to the complete outage on both the CTS and FEVI systems, thereby triggering a potential gas supply service outage to 660,000 customers. A new station bypass at Huntingdon Station, is necessary to reduce the risk of a service outage estimated at approximately $7 million.
2. Preload and Stabilize Remaining Right of Way between Delta Station and Tilbury Station to stabilize most of the Right of Way in the Burns Bog to mitigate the risk of ground movement and associated pipe damage. No estimate provided.
3. The Coastal Transmission System and Intermediate Pressure System sustainment projects, required in order to ensure the ongoing safety, integrity, and reliability of the system, estimated at approximately $220 million.
4. The Kingsvale-Oliver Reinforcement Project (KORP). The reinforcement would further integrate and expand service using available capacity on T-South and SCP. The KORP provides an opportunity to deliver a growing supply of British 26 Columbia gas to the Pacific Northwest and California markets. *Estimated at $440* million.

(FEI Exhibit B-1, pp. 250–253; FEI Exhibit B-11, BCUC 1.10.3' T4:665)

Coastal Transmission System upgrades and KORP alone amount to approximately the same amount as the projected formula driven spending in the entire PBR period (Exhibit B-11, BCUC 1.10.3).

2.3.5.6.2 FBC's Capital Spending

FBC estimates a little over $300 million of formula capital in the PBR period. The estimated CPCN projects amount to somewhat less than half of the estimated formula capital. FBC lists the following proposed CPCN projects:

Table 2.27 Proposed FBC CPCN Projects

Project	Application Filed	Est Start Date	Est In Service Date	Est Cost ($ million)
Kelowna Bulk Transformer Capacity Addition	2016	2017	2019	14.5
Grand Forks Transformer Addition	2016	2017	2019	5.9
Ruckles Substation Upgrade	2015	2016	2019	5.9
Central Okanagan Substation	2017	2018	2019	24
Grand Forks to Warfield Fibre Installations	2014	2014	2015	4.8
Corra Linn Spillway Concrete and Spill Gate Rehabilitation	2016/2017	2015	2033	21.6
Kootenay Long Term Facilities Strategy	TBD	2014	2016	16.4
Upper Bonnington Unit 1, 2, 4 Refurbishment	2015	2016	2019	21.0
Total				**114.1**

(Source: FBC Exhibit B-25, BCUC 2.45.1)

2.3.5.7 The AUC Approach

B&V summarized the criteria for the capital tracker mechanism adopted by AUC as:

1. The project must be outside of the normal course of the company's ongoing operations
2. Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party; and
3. The project must have a material effect on the Company's finances

(FEI Exhibit B-1-1, Appendix D1, p. 8)

PEG considers the AUC's capital tracker requirements to be overly broad. It states that capex projects potentially eligible for tracker treatment should have some combination of the following attributes:

- Large *(*i.e. having a material effect on the company's finances)
- Non-revenue producing
- Not associated with unusually rapid O&M productivity growth that permit project self financing;
- Not reflected in the productivity research on which the X-Factor is based; and
- Required by a government agency or other powerful external party.

(FBC C1-22, BCUC-IR2, 2.9.1)

2.3.5.8 Issues Arising

2.3.5.8.1 The Lumpiness of Large Capital Expenditures

Fortis states that:

> "[g]iven the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system." (FBC Exhibit B-1, p. 55)

CEC submits that "it is clear that CPCN's for major capital projects replacing portions of the system could and would impact the future sustainment capital requirements, as would such projects aimed a [sic] implementing life extension options. CEC submits that this is an area of very loose discipline with regard to the operation of a PBR formula for capital. CEC submits that the Commission can only resolve this by confining the types of capital allowed in the PBR formula." (CEC PBR Final Argument, p. 98)

Fortis states that "These projects, and the lumpiness of the expenditures associated with them, are well outside normal steady-state operations. Indeed, there is no provision for expenditures of these types in the determination of the 2013 Base Capital; hence classification of these projects as Major Capital is appropriate." (Exhibit B2-8, BCUC 3.8.8)

BCPSO expresses concerns about "the potential for the utilities to 'game the CPCN process' by grouping together projects that have historically been included (or ought to be included in) in base capital." In the view of BCPSO, "[i]f Fortis is able to lump costs together to meet the threshold for a CPCN, they may be able to either have costs added to O&M, or have capital that was below the CPCN threshold in the past, now be treated as CPCN, and thus reduce what was historically outside CPCN." (BCPSO PBR Final Argument, p. 21)

With regard to FBC, CEC states that "[a]n inspection of the CPCN projects suggest they are generally routine but lumpy investments, such as the construction of a new substation" (FEI Exhibit C1-13-1, CEC Response to BCUC 1.13.2).

2.3.5.8.2 A Materiality Capital Exclusion Threshold

As previously noted, FEI's $5 million CPCN threshold is a quantitative criteria. Capital projects less than $5 million do not generally require a CPCN although the Commission could so require it. Accordingly, FEI's threshold is very much akin to a materiality threshold that is a capital exclusion based solely on a dollar figure. However, FBC's CPCN criteria, although incorporating a materiality threshold of $20 million are much broader and allow for the Company to determine whether a CPCN is required for capital projects less than $20 million. The notion of a materiality threshold for both companies was explored in the proceeding.

Regarding FEI's $5 million CPCN threshold, Ms. Roy stated that it was originally set in 2004 and "it may be low…. Five million dollars is a fairly small number" (T4:665). However, she also stated that FEI usually don`t have a lot of capital projects with a cost of 5 million, and that "[w]e sometimes have some that are 8 to 9 [million]¸and then after that they tend to jump to more than $20 million". (T4:665–666)

Mr. Swanson stated that when the $20 million CPCN threshold criteria was set for FBC, it represented roughly 1 percent of revenues (T4:665). Ms. Roy commented that "one percent of our [FEI's] delivery revenue requirement is about $65 million. That's a pretty high CPCN threshold. It would definitely require some kind of recalibration of either the base or the X-Factor". (T4:666–667)

2.3.5.8.3 Timing of Capital Spending

Fortis states that "[t]he Companies have some control over capital spending otherwise it would be inappropriate to include capital in the PBR formula." (Fortis Exhibit B2-11, CEC 3.5.2)

CEC submits that

> "[i]n fact they have quite a lot of judgment control on when to undertake sustainment capital but very little control over the need for the sustainment capital." In its view, "[i]t is the control over the timing of the sustainment and other capital that enables the Utilities to underspend a capital formula without consequences, particularly when the capital formula has been set sufficiently high." It submits that the Commission should focus close attention to the areas where the Utilities have judgment latitude because these are the highest potential areas where unwarranted rewards for no real savings can occur." (CEC Final Argument, p. 96)

2.3.5.8.4 Impact of CPCN Capital on O&M

Capital projects funded outside the PBR formula may give rise to subsequent reductions in spending relative to the formula driven O&M spending envelope. For example, a CPCN project that is tracked outside the formula to replace an older leak-prone pipe will, in all likelihood, reduce the ongoing maintenance requirements.

FEI states:

> "CPCN projects may reduce some O&M costs. Those O&M reductions may or may not be covered under the PBR Plan. For example, a CPCN project that reduced electric lines losses results in lower purchased power expenses and would pass through automatically because purchased power costs are not part of the PBR Plan mechanism. A similar result would occur for the gas system where new pipe replaces older leakier pipe and the quantity of lost and unaccounted for gas would be reduced. Some O&M expenses such as leak surveys are still required even for new installations so there is no saving at all. Finally, there may be fewer repairs on the new segments of main but it is also true that other segments have aged and the expected repairs increase." (FEI Exhibit B2-8, BCUC 3.11.3)

FEI also submits that "all CPCN applications, whether submitted during the PBR term or during a cost-of-service RRA test period, should include a full assessment of the costs and benefits of the project. This is a standard requirement in the Commission's CPCN Application Guidelines." (FEI Exhibit B2-1 BCUC 3a.305.1)

Fortis agrees that CPCN projects may reduce some O&M costs and that these reductions "may or may not be covered under the PBR Plan." However, when asked about the upcoming CPCN projects, FBC stated that "[n]one of the projects identified above are forecast to result in incremental capital and/or O&M cost savings during the proposed PBR term and trailing ECM window." (FBC Exhibit B-24, BCUC 2.43.2; Exhibit B2-8 BCUC 3.11.3) FEI argues that "not all CPCN projects generate future savings. Indeed some CPCN projects involve both capital and/or O&M cost increases." (FEI Exhibit B2-8, BCUC 3.11.3)

Fortis further states that

> "[t]he impact of CPCN projects and the 'potential' savings or costs that may result from them are already accounted for in the PBR formula through FEI's proposed X-factor. As discussed in B&V's TFP studies, the electric and natural gas utility industry-wide productivity factors are well into the negative zone while FEI's and FBC's proposed X-factor is a positive 0.5%. A contributing factor to FEI and FBC being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans." (FEI Exhibit B2-1 BCUC 3a.305.2)

Fortis submits that PEG's discussion "is premised on a plan such as that that exists in Alberta. And even then, on the type of capital tracker that the AUC has moved away from, recognizing that it is unworkable in practice." (T8:1399)

CEC submits that "all O&M savings or other cost reduction that are a result of CPCN activity should be flowed through as a matter of course and that the Utilities proposition to not do so is misaligned with customer interests" (CEC PBR Final Argument, p. 85).
In the case of FBC, Mr. Swanson testified that "what we found is over that five-year period, the net result of all those CPCNs was actually an increase in O&M. So had we flowed all that through the formula you would have in fact increased O&M not decreased O&M because there's not a lot of CPCNs where … the theoretical CPCN where you invest in some piece of infrastructure that makes a bunch of labour go away. Those types of CPCNs simply don't often exist in our world." (T2:332)

However, CEC cites a specific example of O&M benefits resulting from a capital project. FBC proposes to track AMI outside its PBR plan which CEC interprets to mean that it does not impact the PBR formula. It states that the AMI impact for 2018 includes savings of $4.4 million in meter reading savings which are partially off-set in new operating costs for a net reduction of approximately $2.8 million in O&M. When the savings are excluded, the PBR O&M forecast increases from $63.3 million to $66.1 million. (CEC Final Argument, p. 83)

CEC submits that "there is no process to ensure that all AMI O&M benefits are captured and excluded. The AMI hearing identified many benefits that were not defined and or estimated. To the extent any of these are O&M related and outside of the company process for deducting them to flow them through to customers, they may result in sharing with the Utility shareholder inappropriately. CEC submits this would be a misalignment with customer interests." (CEC Final Argument, p. 83)

2.3.5.8.5 Impact of Price Spikes

CEC submits that

> "the potential for capital costs to be driven by market supply demand conditions resulting in significant price spikes, which subsequently have subsided. The nature of such perturbations in the market makes the application of a formula highly problematic because they can lead to potential under allowance for capital expenditures and risks to the system or if embedded into the base potential over allowance in the formula putting the customers at risk of paying for phantom savings of underspending an overly generous formula. CEC submits that the current PBR proposals for capital are more likely to contain the later [sic] problem." (CEC PBR Final Argument, pp. 106–107)

Commission Determination

The Panel will address the issue of capital excluded from formula driven spending by addressing the following questions:

1. Should there be any capital exclusion criteria at all?
2. Is the CPCN Criteria an appropriate Exclusion Criteria?
3. Is a Dollar Threshold Appropriate?
4. What should the Quantum of a Dollar Threshold be?

<u>Should there be any Capital Exclusion Criteria at all?</u>

In the Panel's view, the more capital excluded from formula spending, the fewer benefits of PBR accrue to ratepayers and shareholders alike. Excluding significant amounts of capital reduces the ability of the utility to achieve operational efficiencies. However, it also provides opportunities for a utility to game the system, such as by combining smaller projects into larger projects that will be excluded from the formula. Also, by including more capital in the formula, larger, and potentially lumpier, projects are included. This gives rise to challenges to the utility to manage and also possibly increases risk to ratepayers and shareholders alike.

The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope. There are certain capital projects that are outside the normal course of business, that the utility is required to undertake and that the utility has little or no control over should not be included in the formula. In our view, these projects should be accorded exogenous treatment, in much the same way that certain O&M expenses are.

It also may be appropriate to consider an exclusion criteria based on the size of the project and we will examine this issue in the following sections.

Is the CPCN Criteria an Appropriate Exclusion Criteria?

The Panel is not persuaded there is any basis to link exclusion from CPCN requirement to exclusion from the PBR formula. Section 45 of the UCA requires that "a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity requires or will require the construction or operation." Exclusion from this requirement is based on a balance of regulatory efficiency and the broader public interest. Otherwise, all capital projects would be subject to CPCN requirements.

In the case of FEI, the CPCN threshold limit amounts to a materiality threshold of $5 million. However, in the case of FBC, with the number of projects below $20 million subject to CPCN requirements, the CPCN threshold doesn't provide a clear, transparent materiality limit. In proposing the CPCN exclusion criteria as the PBR capital exclusion criteria, Fortis is effectively arguing that in the case of FEI a $10 million dollar project is too lumpy, yet for FBC a $10 million dollar project could, unless otherwise subject to CPCN requirements, be managed as part of the formula spending envelope. In the Panel's view, this supports the conclusion that the use of CPCN criteria as an exclusion criterion for the PBR formula is arbitrary. Further, the CPCN requirements do not differentiate between routine capital projects and projects that are not routine. Therefore, they are not a good indicator of the exogenous nature of the capital project.

Is a Materiality Threshold Appropriate?

Many parties argue that the lumpy nature of large capital projects is more likely to result in a variance between formulaic and actual spending. The Panel does not agree that larger capital projects necessarily have a propensity for lumpiness. It is not necessarily the magnitude of the project that contributes to the lumpiness, but the annual spend-which depends upon both the total spending and the duration of the project-and the number and nature of other projects undertaken concurrently. For FBC, for example, under the formula, approximately $20 million to $30 million dollars will be spent each year on a variety of sustainment projects with different costs and durations. There does not seem to be a significant difference between a one-year project with a cost of $2 million that is included in the capital formula spending envelope and $2 million spent in one-year of a three year $6 million CPCN project that is excluded from the formula.

As CEC asserts and Fortis acknowledges, the utilities do have some control over capital spending. The Panel expects the utilities to take a proactive role in the management of their capital projects, regardless of the materiality of the threshold, so there is as little variance as possible while ensuring that there is no underspend of the type that CEC alleges have occurred during the previous PBR period.

Parties also raised concerns that there is an opportunity for the utility to combine smaller projects into a larger project that will trigger a CPCN requirement, and thereby exclude all of those smaller projects from the PBR formula driven spending envelope. Unless those smaller projects are replaced by other small projects, the result will be, all else equal, an under-spend relative to the formula driven spending envelope.

There are two provisions in the PBR mechanism that mitigate the impact of this and thereby protect ratepayers in this eventuality. The first is Fortis' proposed dead-band around the actual capital spend relative to the spending envelope, which would be triggered if the under-spend was of sufficient magnitude and/or duration. **The Panel finds this an appropriate mitigation, providing**

the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula.

In addition, the earnings sharing mechanism, which the Panel approved elsewhere in this decision, ensures that ratepayers share half of the benefits of that underspend, although that may amount to returning half of the money that has, in some sense, been over-collected from them because of the underspend.

In the Panel's view, a further potential mitigation is to increase the limit of the size of capital project that is subject to formula spending. The larger the limit, the less likely that smaller projects can be combined.

If a Materiality Threshold is Set, at What Level Should it be Set?

The Panel is of the view that, if a materiality threshold is appropriate, it should be set at such a level that considers both the lumpy nature of projects and the ability of the companies' professional management teams to manage that lumpiness. The threshold should reflect a balance of risk with the benefits of the operational efficiencies that arise from the more holistic approach to management provided by the inclusion of capital within the formulaic spending envelope. In the following section the Panel will consider the quantum of the threshold.

However, a number of arguments have been raised against a higher materiality threshold. FEI and FBC argue that a contributing factor to being able to accept large implicit stretch factors is that the capital costs of CPCN projects are not part of their PBR plans. The Panel does not agree with this argument. The Panel has applied relatively small stretch factors to each utility. Further, neither the B&V nor the PEG study excluded capital spending for CPCN Projects or even applied a threshold of materiality for capital spending in their studies - the X-Factor accepted by the Panel is based on a TFP trend study that included all of the capital spending of the utilities. Accordingly, as Dr. Lowry testified, if the X-Factor is to be applied to a capital spending envelope that is substantially less, it requires adjustment. The Panel has not made any such adjustment and considers the X-Factor approved in this proceeding to be appropriate for use with an increased materiality limit. If any adjustment is required, in the Panel's view an upward adjustment may be appropriate to account for the proposed CPCN-based exclusion criteria. However, at this time, the Panel declines to make such an adjustment.

Interveners raise concerns about the formulaic approach to capital spending generally, arguing that even the proposed approach, with its CPCN exclusion, leaves the utilities significant opportunity to underspend. To the extent that this is the case, increasing the threshold will provide even greater opportunities to underspend.

The Commission Panel does not disagree with these intervener concerns. However this is not sufficient reason to warrant either disallowing the capital spending formula entirely or even keeping the CPCN limit as proposed. It is only by increasing the amount of capital covered by formula that the full benefits of PBR can be achieved.

However, the Panel does not consider it appropriate to set a different exclusion threshold at this time and will seek further comment on this issue as set out in the Summary section below.

<u>Summary</u>

In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate. There are circumstances where the nature of the project justifies exclusion from the formula (i.e. an exogenous factor). However, the lumpiness of the expenditures is not, in itself, sufficient criteria. As previously stated, the Panel expects the utilities to manage their capital projects in a manner that is consistent with the spending envelope provided by the PBR plan. Further, there may be circumstances where capital that is not exogenous should be excluded from the formula. The threshold for such exclusion should be based on a dollar-amount**.**

The Panel invites further submissions on this matter, specifically on the issues set out below:

1. What exogenous criteria should be established for excluded capital?

2. In addition to a capital exogenous factor, is a materiality threshold required?
3. If a materiality threshold is appropriate, at what level should it be set in order to realize the full benefits of PBR? Given your responses to 1, 2 and 3, what should the base capital be set for FEI and FBC for 2016?
4. Is a cumulative dead-band of 15% over two years sufficient to protect both ratepayers and shareholders?
5. What reporting procedures should be in place to allow parties sufficient time to review proposed capital spending?
6. Should the CPCN threshold be raised to match or exceed the PBR formula materiality threshold?

Submissions should be received in accordance with the following timetable:

Submission from Fortis	December 31, 2014
Submissions from Interveners	April 30, 2015
Reply Submission from Fortis	June 30, 2015

The Commission will provide further direction concerning process following Fortis' reply.

Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.

In making this determination, we are mindful of the concerns of Interveners and are of the view that a two year cumulative dead band is appropriate and considers 15 percent over or underspend an appropriate setting for a two year cumulative dead-band. Accordingly, the Commission Panel directs, in addition to the one year 10 percent dead-band previously approved, a two year cumulative 15 percent dead-band for all Fortis' formulaic capital spending.

Other Issues

The Impact of Capital on O&M

To the extent that a project results in a reduction of maintenance expenditures, the utility will have the opportunity to underspend its maintenance spending envelope. The Panel recommends that, if capital associated with a particular CPCN is excluded from the formula, the CPCN review of that project should include an assessment by the Commission of any potential impact of the project on O&M. If appropriate, an adjustment to the formula based O&M spending envelope should then be made.

AMI Capital

With regard to CEC's concern about the benefits of the AMI project not being captured, the Panel does not agree. Table B6-5 in the Application and the spreadsheet at Attachment 1.1 of Panel IR 1.1 show O&M formula spending reduced by over $7.5 million to account for AMI benefits over the PBR period.

2.3.6 Mid-Term Review and Annual Review Process

The purpose and content of the Annual Review was a significant point of contention in the hearing. Fortis envisaged the Annual Review process as primarily an information sharing forum similar in scope and process to Annual Reviews held in previous PBRs (FEI Exhibit B-1, pp. 78–79; FBC Exhibit B-1, pp. 71–72). A number of interveners saw the Annual Review as having a broader scope and dealing with a variety of issues. Fortis submits that a clear definition of the purpose and scope of the Annual Review is required if the PBR is to operate successfully. (Fortis PBR Reply, p. 54)

The Mid-Term Review is proposed by the Companies as an opportunity for stakeholders to review the outcomes of the PBR and suggest adjustments to certain planned parameters if required. The Mid-Term Review will form part of the third Annual Review, acting as a "checkpoint" that allows parties to address discrete flaws in what is otherwise a workable PBR plan. CEC was the only intervener to raise issues specific to the Mid-Term Review. (FBC Exhibit B-1, pp. 69, 70; FEI Exhibit B-1, pp. 76–77)

Unlike past PBRs, which were put in place following a negotiated settlement process, under this PBR the Annual and Mid-Term Review processes are taking place after a hearing process where stakeholders expressed serious reservations with the applied for PBR, with some parties opposing the use of a PBR altogether. In this environment, the Panel considers there is a need for the review processes to be more extensive, at least in the first few years, in order to build trust between the Companies and stakeholders and to ensure that the PBR process is working fairly and effectively.

Fortis' Annual Review Proposal

Fortis envisages the Annual Review to be identical to the process that was undertaken in previous PBRs. This process would consist of a workshop, one round of information requests from the Commission and interveners, letters of comment, and a Commission determination of rates. Fortis states that as part of the Annual Review process, the following actions will occur:

- The Companies will present the current year's projections and the upcoming year's forecasts for a number of measures;
- Flow-through items will be trued-up to actuals for the prior year; and
- Inputs in the PBR formula, such as inflation and customer growth will be re-forecast.

(FEI Exhibit B-1 p. 79; FBC Exhibit B-1, pp. 71–72; Fortis PBR Final Argument, p. 59)

Intervener Submissions

The issues or concerns raised by interveners with respect to the Annual Review include:

- The inadequacy of treatment of SQI's (COPE Final Argument p. 51). If the SQI's targets are not achieved there should be the opportunity for interveners to make submissions that the incentive earnings of the Company are reduced (BCPSO PBR Final Argument, p. 20);
- The reviews are too limited. There should be an opportunity to review PBR performance and to make improvements to the PBR Plan, under Commission oversight. There should be a greater opportunity for stakeholders to get information and pursue any areas that are deemed necessary to ensure the ongoing applicability of the PBR formula. (CEC PBR Final Argument, pp. 162–163);

- There should be a review of efficiency proposals at the Annual Review (CEC PBR Final Argument p. 26);
- The Annual Review process will be much more expensive than estimated by Fortis. The regulatory efficiencies expected by Fortis will not be achieved. (CEC PBR Final Argument, pp. 11–12; BCPSO PBR Final Argument, para. 13); and
- Fortis should be required to disclose all exogenous events that result in benefits to the ratepayer at the Annual Review (CEC PBR Final Argument, p. 158).

Fortis Reply

The Companies responded to these criticisms by stating that:

- If there was concern about a deterioration of service that was seen to be due to the fault of the Company, there would be significant discussion at the Annual Review, potentially leading to a decision by the Commission (T5:1051).
- While the review of the cost of service will not be as detailed as in a revenue requirements application, since controllable costs are largely formula driven, the Annual Review will provide more frequent reporting than would normally exist under Cost of Service regulation (Fortis PBR Final Argument, p. 59).
- One of the key benefits of the PBR will be eliminated if Fortis is required at each Annual Review to provide a detailed justification of individual efficiencies achieved in the prior year (Fortis PBR Reply, p. 54).
- The regulatory cost savings under past PBR plans provide an evidentiary basis to conclude there will be direct cost savings under the proposed PBR plan. Given that the most contentious aspects of the Companies' revenue requirements will be determined by the formula, it is logical to expect both direct and indirect savings. Intervener arguments on regulatory cost are founded on errors or flawed logic (Fortis PBR Reply, pp. 15–16).

Commission Determination

The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended. This will address some of the concerns expressed by CEC with respect to the consensus requirement to bring forward issues and with respect to the timing of airing concerns related to PBR elements. The Panel finds that the enhanced ability to assess the PBR Plan at Annual Reviews also addresses the concern expressed about the symmetry of the financial distress criterion. If the PBR plan is seen by any stakeholder as inducing financial distress, the issue may be raised at the Annual Reviews and if not resolved, brought to the Commission for resolution.

In what follows, the Commission Panel sets out the activities to be undertaken in all Annual Reviews before describing topics to be covered in the first Annual Review.

<u>All Annual Reviews</u>

The Commission directs that the Annual Review process include the following:

1. **Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns.**
2. **Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below:**
    a. **Customer growth, volumes and revenues;**
    b. **Year-end and average customers, and other cost driver information including inflation;**
    c. **Expenses (determined by the PBR formula plus flow-through items);**
    d. **Capital expenditures (as determined by the PBR formula plus flow-through items);**
    e. **Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;**
    f. **Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and**
    g. **Any proposals for funding of incremental resources in support of customer service and load growth initiatives.**
3. **Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives (see Section 2.3.2 for a more detailed discussion of the ECM).**
4. **Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from**

the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers (see Section 2.2.4 for details).

5. **Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service (see Section 2.3.3.2 for details).**
6. **Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs.**
7. **Assess and make recommendations to the Commission on the scope for future Annual Reviews.**

Given this more comprehensive Annual Review, the Panel is of the view that a Mid Term Review will not be required. **Accordingly, Fortis' request for a Mid-Term Review is denied.**

2.3.6.1 Unique First Annual Review Requirements

The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.

3.0 OTHER REVENUE REQUIREMENTS

3.1 Key Issues

3.1.1 Load Forecasts

3.1.1.1 Background and Methodology

The FEI demand forecast is a key input to the calculation of the rates that FEI will require for the term of the PBR. The Company categorizes customers into three major groups: Residential, Commercial and Industrial (Exhibit B-1, p. 89). FEI's 2014 demand forecast was updated in the February 21, 2014 Evidentiary Update to reflect the adoption of Rate Schedule 46 for LNG (Exhibit B-1-5, Covering Letter, p. 6). FEI states that the 2014 demand forecast is consistent with recent actuals and that the demand forecast for future years will be updated in the Annual Review Process. (Exhibit B-1, p. 105; FEI Non PBR Final Argument, p. 8)

The cumulative FEI demand is the summation of the Residential, Commercial and Industrial demand forecasts. The individual demand forecasts were prepared according to the methods used in prior RRAs. The demand forecasts for Residential and Commercial customers are determined by multiplying the projected number of customer accounts (including account additions) by the normalized use per customer (UPC) for each rate class. Industrial demand is forecast through the annual Industrial Survey. In the Industrial Survey, industrial customers provide their forecast monthly and annual consumption and the data is used to produce forecast demand for each of the industrial rate schedules. FEI states that the accuracy of the forecasts is verified by comparing the historical demand forecasts with historical data. (Exhibit B-1, pp. 90, 96)

3.1.1.2 Rate Stabilization Adjustment Mechanism

FEI requests approval of the Rate Stabilization Adjustment Mechanism (RSAM) credit rate rider of $0.120/GJ, as set out in Section E Schedule 63 of the Application, for Residential and Commercial customers effective January 1, 2014 (Exhibit B-1-5, p. 6). When the RSAM was approved in 1994, one benefit cited was the reduction of sales forecast risk to utility shareholders from "weather sensitive" residential and commercial customer classes during the winter.[15] When variances between actual and forecast UPC volumes used to set residential and commercial rates occur, FEI records the resulting delivery charge differences in the RSAM deferral account. The RSAM Delivery Rate Rider 5 refunds or recovers the balance in the RSAM deferral account to the RSAM rate classes. (Exhibit B-1, p. 98) The Application includes a proposal to change the amortization period for the RSAM deferral account from three years to two years. This will be discussed in the Accounting Policies Section 3.3.2 of this Decision. The ending 2013 balance of RSAM is $21.3 million (Exhibit B-1-5, Section E, Schedule 47).

Commission Determination

Consistent with previous revenue requirements decisions, **the Commission Panel approves the RSAM rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23 and a of a credit of $0.120/GJ, effective January 1, 2014**.

3.1.1.3 Expanded RSAM to Include Industrial Revenues

Unlike the residential and commercial customers, variances in industrial customer demand are not captured by the RSAM and, as a result, FEI loses/gains from over/under forecast of industrial consumption. The industrial demand forecast was raised as an area of concern in IRs. In particular, the actual Rate Schedule 22 revenues have exceeded the forecast revenues each year from 2004–2012. During the 2004–2009 PBR, ratepayers received a cumulative benefit of $3.8 million due to the 50/50 sharing of the Rate Schedule 22 revenue variances as part of the Earnings Sharing Mechanism. For the 2010-2012 non PBR period, the Rate Schedule 22 revenue variances resulted in a cumulative benefit of $5.8 million to FEI's shareholders. (Exhibit B-24, BCUC 2.243.1.2.2)

[15] In the Matter of BC Gas Utility Ltd. 1994/95 Revenue Requirements-Phase 2-RSAM & Sales Forecasts Decision, p. 4.

Table 3.1 Sharing of Rate Schedule 22 Revenue Variance

Rate Schedule 22

Year	Revenue Decision	Revenue Actual	Revenue Variance	Tax Rate	Income Tax	Earnings Impact Ater Tax Pre-Sharing	ESM 50%	Earnings Post Sharing	Tax Rate Less Surtax Rate	Customers' Share of Surplus Pretax	Cumulative Customers' Share of Surplus
2004	$30,155	$30,326	$ 171	35.62%	$ (61)	$ 110	$ (55)	$ 55	34.50%	$ 84	$ 84
2005	$29,424	$31,066	$ 1,642	34.87%	$ (573)	$ 1,069	$ (535)	$ 535	33.75%	$ 807	$ 891
2006	$30,461	$30,743	$ 282	34.12%	$ (96)	$ 186	$ (93)	$ 93	33.00%	$ 139	$ 1,030
2007	$29,114	$29,388	$ 274	33.00%	$ (90)	$ 184	$ (92)	$ 92	33.00%	$ 137	$ 1,167
2008	$26,321	$30,081	$ 3,760	31.50%	$(1,184)	$ 2,576	$(1,288)	$ 1,288	31.50%	$ 1,880	$ 3,047
2009	$25,674	$27,153	$ 1,479	30.00%	$ (444)	$ 1,035	$ (518)	$ 518	30.00%	$ 740	$ 3,786
2010	$26,457	$28,932	$ 2,475	28.50%	$ (705)	$ 1,770	N / A	$ 1,770	N / A	N / A	
2011	$26,748	$29,218	$ 2,470	26.50%	$ (655)	$ 1,815	N / A	$ 1,815	N / A	N / A	
2012	$30,733	$33,697	$ 2,964	25.00%	$ (741)	$ 2,223	N / A	$ 2,223	N / A	N / A	

(Source: Exhibit B-24, BCUC 2.243.1.2.2)

Intervener Submissions

CEC submits that industrial revenues, like residential and commercial revenues, should be subject to a regulatory mechanism that adjusts forecast revenues to actual revenues (CEC, PBR Final Argument, p. 177). In addition, the potential for the RSAM to be expanded to include industrial customers and the question of whether the absence of an RSAM mechanism was a disincentive for FEI to pursue EEC measures for industrial customers were discussed in IRs. (FEI Non PBR Final Argument, p. 9)

Fortis Reply

FEI states that the CEC's proposal to expand the RSAM to include industrial revenue should be rejected. FEI submits that a decoupled Industrial RSAM is unnecessary because, the variable revenues from industrial customers would not significantly affect the revenues of FEI. The Company also states that including Rate Schedules 7, 27and 22 customers in the RSAM would be inconsistent with the interruptible service they receive. (Exhibit B-11, 1.212.1; FEI Non PBR Reply, p. 3)

Commission Determination

The objective of the RSAM is to reduce the forecast risk due to weather, but weather is not the primary cause of variances in industrial demand. As stated by FEI, industrial demand has increased as a result of declining gas prices. The Panel agrees with FEI that expanding the RSAM to include amounts for interruptible customers would be difficult, given the contractual nature of their service.

However, the Commission Panel considers the consistent under estimation of Rate Schedule 22 demand and revenue to be indicative of bias in the industrial forecast. Adjusting FEI's Rate Schedule 22 forecast to correct for a known forecast bias is the applicable remedy. Therefore, **the Commission Panel does not approve the establishment of an Industrial RSAM**. This issue of forecast bias will be discussed in the Industrial Customer Usage Rates and Demand Forecast Section 3.1.1.6 of the Decision.

With respect to the discussion regarding lack of an RSAM mechanism inhibiting the development of EEC measures for industrial customers, there is insufficient evidence in this proceeding to make such a determination.

3.1.1.4 Residential Customer Usage Rates and Demand Forecast

The Residential Demand forecast is the result of multiplying the normalized forecast use per customer (UPC) by the estimated number of residential accounts (including account additions). FEI states there has been a consistent decline in UPC with the exception of 2012, although the customer count adjustment that occurred when the new customer information system (CIS) was implemented resulted in UPC increases for Rate Schedules 1, 2 and 3 in 2012. FEI also notes that residential customer growth has not offset the decline in average UPC and has resulted in an overall continued decline in residential demand. (Exhibit B-1, pp. 90, 93, 106)

FEI submits that the Conference Board of Canada housing start forecast is a suitable proxy for the Company's customer additions forecast, given the 90 percent correlation between housing starts and net residential customer additions (Exhibit B-1, p. 95). The Company also notes that the net residential customer additions forecast consists of a single and a multi-family dwelling forecast and that this methodology is consistent with the 2012–13 RRA (Exhibit B-1, p. 94).

There were no Intervener submissions on the Residential Demand forecast.

Commission Determination

The Commission Panel approves the 2014 Residential Demand forecast. The FEI residential energy demand forecast methodology is the same methodology in previous revenue requirements decisions. The forecast decline in the residential UPC is consistent with historical trends,

3.1.1.5 Commercial Customer Usage Rates and Demand Forecast

The Commercial Demand is determined by multiplying the normalized forecast commercial UPC by the commercial accounts (including account additions), for each commercial rate schedule. (Exhibit B-1, p. 90) FEI states that Rate Schedule 2 UPC is forecast to be stable and increase by less than 1 GJ per year, while Rate Schedule 3 UPC are expected to increase by 25 GJ/year. Consistent with historical trends, the Rate Schedule 3 UPC is forecast to increase by 0.7 percent per year while the Rate Schedule 23 UPC is expected to increase by 2.8 percent per year. (Exhibit B-1, pp. 100–101)

None of the Interveners made submissions with respect to the Commercial Customer Demand Forecast.

Commission Determination

The Commission Panel approves FEI's 2014 Commercial Demand forecast. The forecast utilizes a previously approved methodology that has provided reasonable results in the past. In addition, any UPC variances are managed through the RSAM, which protects the interest of ratepayers.

3.1.1.6 Industrial Customer Usage Rates and Demand Forecast

The Industrial Energy Demand is the forecast demand as self-reported by industrial customers in the annual Industrial Demand Survey. Customers participating in the Industrial Demand Survey provide their forecast monthly and annual consumption. The data from the survey is used to produce forecast demand for each of the industrial rate schedules. FEI also assumes that there are no industrial customer additions during the forecast period and the Company only increases the forecast number of industrial customers when it receives specific knowledge of the customer. (Exhibit B-1, p. 96) The 2012 Industrial Survey participants included 56.8 percent of industrial customers representing 88.5 percent of the total industrial demand (Exhibit B-1, p. 97).

There have been consistent variances in Rate Schedule 22 forecasts. FEI states that over time the sum of over and under forecast variances are expected to cancel each other out producing a net variance of zero and in the long run ratepayers, as well as FEI, should not be financially disadvantaged by industrial forecast variances. In spite of these assurances, in the case of Rate Schedule 22 revenues, this expectation is contradicted by the fact that actual Rate Schedule 22 revenues have exceeded the forecast revenues every year from 2004–2012. FEI has under forecasted Rate Schedule 22 volumes every year from 2008-2012, with variances ranging from -7 percent in 2008 to -50 percent in 2011 and an average of -21 percent over the five year period, as outlined in Table 3.2.. (Exhibit B-11, BCUC 1.67.2; Exhibit B-11, BCUC 1.64.3; Exhibit B-24, BCUC 2.243.1.2.2)

Table 3.2 2004–2012 Rate Schedule 22 Variance as a Percentage of Forecast

Year	Forecast (GJ)	Actual (GJ)	Variance as a % of Forecast
2008	20,967,980	22,487,971	-7%
2009	18,166,574	19,745,960	-9%
2010	19,183,662	22,494,945	-17%
2011	16,757,447	25,133,369	-50%
2012	23,233,216	28,807,092	-24%
Total	98,308,879	118,669,337	
Average Variance			-21%

(Source: Derived from Exhibit B-11, BCUC IR, 1.64.3)

When asked for recommendations to improve the accuracy of the Rate Schedule 22 demand forecast, FEI stated that it had no recommendations at this time (Exhibit B-24, BCUC 2.243.1.2.3).

FEI states that falling gas prices may have resulted in higher than forecast industrial customer use, but this is not a reason to change industrial customer forecast methodology. In addition, FEI submits that the current methodology was approved by the Commission in the past, including the 2012-2013 RRA FEU Decision. (FEI Non PBR Final Argument, p. 12)

Under the proposed PBR Plan, variances between actual and forecast industrial revenues will be subject to the 50/50 earnings mechanism. This issue is further discussed in Section 2.2.5, Flow-Through Items (Exhibit B-24, BCUC 2.243.1).

Commission Determination

Given the consistent under forecasting of Rate Schedule 22 demand the industrial forecast methodology is no longer appropriate. FEI stated that while industrial revenue variances are subject to the 50/50 earnings sharing mechanism. However, the sharing of under forecasting of

Rate Schedule 22 revenues does not address the accuracy of the industrial demand forecast methodology. Given the historical bias in the Rate Schedule 22 demand forecast, **the Commission Panel does not approve the FEI's 2014 Rate Schedule 22 demand forecast**. Moreover, FEI has not provided any recommendations to improve the accuracy of Rate Schedule 22 demand forecast and Rate Schedule 22 has been under forecast by an average of 21 percent from 2008-2012. Therefore, **the Commission Panel directs FEI to increase the 2014 Rate Schedule 22 demand forecast by 21 percent.** This represents the average variance between forecast and actual over the past five years.

The Commission Panel further directs FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices, for review at the 2015 Annual Review.

3.1.1.7 Natural Gas for Transportation Demand Forecast

FEI's Natural Gas for Transportation (NGT) program provides fueling stations to compress, liquefy and dispense natural gas to customers for use as transportation fuels (CNG and LNG).

FEI delivers CNG and LNG through the Greenhouse Gas Reductions Regulation (GGRR) and non-GGRR stations using Rate Schedules 6P, 25, 16 and 46. The forecast NGT demand is incremental to the Total Normalized Energy Demand. (Exhibit B-1, p. 106; Exhibit B-1-1, Appendix H, p. 1; Exhibit B-1-5, Attachment 4, Appendix H, p. 13, Attachment 5, p. 3) FEI states that its forecast of NGT demand volumes is based on its forecast number of vehicle additions (Appendix H, p. 1; Exhibit B-1-5, Attachment 4, p. 9). FEI also states that the forecasts provided in its February 21, 2014 evidentiary update include the impact of recent information regarding vehicle additions, actual consumption, Commission decisions, legislation and other factors. (Exhibit B-1-5, Attachment 4, Appendix H, p. 6)

There were no Intervener submissions on this issue.

Commission Determination

Given that the number of NGT vehicles in operation drives NGT demand the Commission Panel considers the expected number of CNG and LNG vehicle additions a reasonable method for forecasting NGT demand. **The Commission Panel approves FEI's 2014 NGT Demand forecast.**

3.1.2 Determining the Base O&M

The Panel will review FEI's proposed 2013 Base O&M. We are mindful of the upcoming amalgamation, effective January 1, 2015, which will require a rebasing of the O&M. Accordingly, the determination made in this section is applicable only to the calculation of 2014 revenue requirements.

FEI proposes a 2013 Base O&M Expense of $229.489 million (Exhibit B-1-5, Attachment 4, Application Section B6, p. 55). The 2013 Base O&M forms the starting point for the controllable O&M costs to which the PBR formula will be applied over the PBR term. For the purposes of this Decision, the 2013 Base O&M will be referred to as the Opening PBR O&M Base.

FEI arrives at the Opening PBR O&M Base by starting with the 2013 Approved O&M of $236.003 million, which was approved as part of the 2012–2013 FortisBC Energy Utilities Revenue Requirements Application (2012–2013 FEU RRA), and then making the following adjustments:

(i) a reduction related to "Sustainable Savings" that were realized in 2012 and 2013;
(ii) an increase related to actual incurred 2013 "non-controllable" O&M that is held in deferral accounts, including PST, BCUC Fees, Insurance, and Pension and OPEB; and
(iii) a reduction related to proposed Accounting Changes which reclassify certain items from O&M to Capital, including Annual Software Costs and the Retiree Portion of Pension and OPEBs.

Table 3.3 shows FEI's derivation of its Opening PBR O&M Base:

Table 3.3 Derivation of Opening PBR O&M Base ($ thousands)

		Productivity		2013 Deferrals		Accounting Changes			
	2013 Approved	(Sustainable Savings)	2013 Sustainable	PST (full year)	BCUC Fees & Insurance	'ension/OPEI O&M portion	'ension/OPEI etiree portio	Software Fees	2013 Base
Operations	63,189	540	63,729	137		3,667	1,704		69,236
Customer Service 1	52,452	(12,498)	39,954	18		1,744	810		42,527
Energy Solutions & External Relations	18,181	1,034	19,215	23		1,012	470		20,721
Energy Supply & Resource Dev	3,738	262	4,000	7		295	137		4,440
Information Technology	25,379	(1,162)	24,217	340		691	321	(1,800)	23,768
Engineering Services & PM	16,956	(1,500)	15,456	58		1,027	477		17,018
Operations Support	12,990	(1,123)	11,867	69		802	373		13,111
Facilities	9,259	324	9,583	40		147	68		9,838
Environment Health & Safety	2,999	(319)	2,681	12		123	57		2,872
Finance & Regulatory Services	14,184	(1,086)	13,099	3	923	597	277		14,899
Human Resources	8,511	(53)	8,458	22		487	226		9,192
Governance	7,935	-	7,935	-	93	-	-		8,028
Corporate	230	(587)	(358)	34		13	(5,851)		(6,161)
	236,003	(16,167)	219,836	782	1,016	10,605	(930)	(1,800)	229,489

1 2013 Projection excludes Customer Service deferred O&M

(Source: Exhibit B-1-5, Attachment 5, p. 4)

Table 3.4 shows the actual results for years 2010 through 2013 as well as the 2012 and 2013 approved results by O&M department:

Table 3.4 Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Actual	2013 Approved
Operations	54,444	55,756	59,806	58,599	64,226	63,189
Customer Service [1]	53,278	56,575	40,737	49,115	36,630	52,452
Energy Solutions & External Relations	14,636	15,456	18,075	17,509	19,022	18,181
Energy Supply & Resource Dev	2,075	3,409	3,488	3,664	3,937	3,738
Information Technology	17,320	18,654	23,442	24,553	24,249	25,379
Engineering Services & PM	13,566	14,329	13,599	16,705	15,297	16,956
Operations Support	10,916	10,580	11,038	12,132	11,718	12,990
Facilities	7,329	6,835	9,563	9,509	9,230	9,259
Environment Health & Safety	2,427	2,445	2,481	2,749	2,680	2,999
Finance & Regulatory Services	12,177	12,064	12,149	13,129	12,872	14,184
Human Resources	8,823	8,170	8,610	8,983	8,305	8,511
Governance	7,368	7,895	7,366	7,602	7,995	7,935
Corporate	2,158	1,439	1,915	2,743	(247)	230
	206,518	213,606	212,269	226,993	215,914	236,003

1 Excludes deferred Customer Service O&M for 2012 and 2013 Actual

(Source: Exhibit B-1-5, Attachment 5, p. 4)

These tables show the 2013 Actual O&M is $20.089 million less than the 2013 Approved O&M. Of this total variance, FEI has classified $16.167 million as "Sustainable Savings" and has incorporated these savings as a downward adjustment to the Opening PBR O&M Base. The remaining $3.922 million variance between 2013 Approved and 2013 Actual O&M are classified by FEI as "Temporary Savings" and are therefore not embedded as reductions to FEI's proposed Opening PBR O&M Base.

Productivity and Sustainable Savings versus Temporary Savings

FEI identifies the following cost drivers which it states are expected to have an impact on O&M during the PBR period: (i) labour inflation and benefits; (ii) customers; (iii) productivity; (iv) demographics; and (v) system reliability and safety (Exhibit B-1, p. 124). Of these five identified cost drivers, productivity is the only cost driver not identified by FEI in the 2012–2013 FEU RRA.

FEI states in the Application: "[i]n identifying O&M forecasts over the PBR Period, departments were encouraged to review processes and identify potential sustainable savings by streamlining processes, leveraging technology and optimizing opportunities for integration with the Electric business… While no specific incremental savings have been identified, the productivity focus has served to manage the number of pressures put forward requiring incremental funding." (Exhibit B-1, pp. 129–130)

FEI forecasts that incremental funding over 2013 Approved funding is required for the Operations, Energy Solutions & External Relations (ES&ER), Energy Supply & Resource Development (ES&RD), and Facilities departments. This is evidenced in the column titled "Productivity (Sustainable Savings)" which shows incremental costs being added to the 2013 Approved amounts in these four departments (see Table 3.3).

FEI stated that it "does not attempt to quantify individual activities that give rise to department O&M over-spend or savings at a total Company level. In assessing productivity, FEI compares department results at the highest and most beneficial level which is the total O&M spend with respect to allowed." (Exhibit B-24, BCUC 2.275.2)

FEI states on page 123 of the Application: "In total, FEI is projecting $9.4 million in sustainable labour savings… The labour savings are primarily driven by integration activities with FBC, savings in IBEW training through the use of new delivery models, refinement of the requirements for supporting capital activities, streamlining processes and the use of technology, and a shift to the use of contractors to allow more flexibility in staffing levels."

When asked to quantify the savings related to integration with FBC, FEI submitted: "… given FEI's approach to ensuring accountability for productivity improvement, it has not required departments to specifically track savings benefits for each of the drivers including savings due to integration. As a result, FEI does not have a comprehensive list of savings benefits due to integration with the electric business at a total Company level." (Exhibit B-24, BCUC 2.277.1.1)

Table 3.5 shows the 2012 Sustainable versus 2012 Temporary savings for O&M:

Table 3.5 2012 Departmental O&M Review ($ thousands)

	2012 Actual	Customer Service Deferral	2012 Sustainable Savings	2012 Temporary Savings	2012 Approved
Operations	59,806		(203)	(1,004)	58,599
Customer Service	40,737	7,435	342	601	49,115
Energy Solutions & External Relations	18,075		(859)	293	17,509
Energy Supply & Resource Dev	3,488		-	176	3,664
Information Technology	23,442		691	420	24,553
Engineering Services & PM	13,599		1,333	1,773	16,705
Operations Support	11,038		1,147	(53)	12,132
Facilities	9,563		10	(64)	9,509
Environment Health & Safety	2,481		211	57	2,749
Finance & Regulatory Services	12,149		265	715	13,129
Human Resources	8,610		53	320	8,983
Governance	7,366		-	236	7,602
Corporate	1,915		-	828	2,743
	212,269	7,435	2,989	4,299	226,993

(Source: Exhibit B-11, BCUC 1.82.1)

The $7.435 million variance in the "Customer Service Deferral" column represents the amount that FEI has recorded in the Customer Service Variance Deferral Account for 2012. This deferral account was approved in the 2012–2013 FEU RRA to record variances between approved and actual O&M for the 2012 and 2013 test years related to the Customer Care Enhancement (CCE) Project. These deferred amounts will be returned to customers through amortization of the deferral account during the PBR term. The Customer Service Variance deferral account is discussed in more detail in the Deferral Accounts Section 3.3.2 of this Decision.

When asked to analyze the 2012 Approved versus 2012 Actual results, FEI submitted: "Temporary savings include initiatives or hiring that was delayed pending the 2012–2013 RRA Decision, employee vacancies where recruiting was planned or underway, as well as any one time events either positive or negative that were not forecast to re-occur." (Exhibit B-11, BCUC 1.82.1)

However, when asked to provide a list, by department, of the O&M expenditures deferred from 2012 to 2013 and to explain whether these deferred 2012 expenditures have now been spent, FEI responded that it "does not maintain a comprehensive list of each of these items. Each department is responsible for their 2013 O&M Projection." (Exhibit B-24, BCUC 2.275.5)

Table 3.6 compares the 2013 Actual O&M to the 2013 Projection and further distinguished between Sustained and Temporary savings:

Table 3.6 Actual O&M versus Projected 2013 Results ($ thousands)

(in $ thousands)	2013 Actual	2013 Projection	2013 Act vs Proj	Sustained	Temporary
Operations	64,237	63,509	728	220	508
Customer Service	36,630	41,825	(5,195)	(1,871)	(3,324)
Energy Solutions & External Relations	19,022	19,215	(193)		(193)
Energy Supply & Resource Dev	3,937	4,000	(63)		(63)
Information Technology	24,249	24,217	32		32
Engineering Services & PM	15,297	15,456	(159)		(159)
Operations Support	11,718	11,867	(149)		(149)
Facilities	9,230	9,249	(19)		(19)
Environment Health & Safety	2,680	2,681	(1)		(1)
Finance & Regulatory Services	12,872	13,279	(407)	(180)	(227)
Human Resources	8,305	8,458	(153)		(153)
Governance	7,995	7,935	60		60
Corporate	(248)	(358)	110		110
	215,924	221,333	(5,409)	(1,831)	(3,578)

(Source: Exhibit B-54, BCUC Panel 1.3.2)

When asked how FEI determined the 2013 Projection, FEI stated that it was "based on the 2013 approved O&M reduced by sustainable savings realized in 2012 and 2013… In determining the sustainable savings for 2013, amongst other factors, 2013 actual data to the end of April 2013 was taken into consideration." (Exhibit B-24, BCUC 2.260.1)

Table 3.5 shows that in 2012 FEI underspent its approved O&M budget by $14.724 million. Of this amount, $4.299 million is characterized by FEI as Temporary savings which means that FEI did not factor this underspent amount into its 2013 O&M Projection. Table 3.6 shows that despite FEI's reduction to 2013 Approved O&M to include 2012 sustainable savings, FEI still underspent its 2013 Projected O&M by $5.409 million. Of this total underspent amount, $3.578 million has been characterized by FEI as Temporary savings. Therefore, when taking into account the results from both 2012 and 2013, $7.877 million of underspent O&M has been classified as Temporary savings. These temporary savings have not been factored into the Opening PBR O&M Base.

As previously stated, for the Operations, ES&ER, ES&RD and Facilities departments, FEI proposes an Opening PBR O&M Base amount that is higher than the 2013 Approved amount. In the case of the ES&ER and the Facilities departments, the proposed Opening PBR O&M Base amounts are higher than both the 2013 Approved and the 2013 Actual amounts.

FEI submits that the appropriate approach to determining the Opening PBR O&M Base is to take a holistic view of O&M requirements as opposed to "cherry picking" subcategories for different treatment. FEI states: "If the 2013 Approved O&M is to be reduced for sustainable savings as FEI has proposed, then, to be consistent, expenditures that were above 2013 Approved levels should also be incorporated into the 2013 Base O&M as FEI has proposed." (FEI Non PBR Final Argument, p. 29)

There are various examples of under-expenditures between 2013 Actual and 2013 Projection/Approved which FEI has classified as Temporary savings related to unfilled vacancies and other employee movement both departmentally and through retirements. These types of explanations are provided by FEI to explain variances between 2013 Actual and 2013 Projected spending in the Engineering Services and Project Management department, the Operations Support department, the Finance and Regulatory Services department, and the Human Resources department. (Exhibit B-54, BCUC Panel 1.3.2)

With regard to the Finance & Regulatory Services department, FEI states: "In 2013, higher labour expenditures are expected due to inflation for labour and benefits, and the filling of existing vacant positions which were put on hold in part pending a decision on amalgamation of the gas utilities" (Exhibit B-1, p. 191). However, in response to BCUC IR 2.291.5, FEI submitted "at this time, four positions still remain vacant given the current proceeding for reconsideration of FEU's Application for Amalgamation of the Gas Utilities and normal staff turnover." (Exhibit B-24, BCUC 2.291.5)

In its Evidentiary Update, FEI reconciles the difference between its Projected 2013 Finance & Regulatory Services O&M provided in the Application and the 2013 Actual results. It states that the

2013 Actual results were $407,000 less than the 2013 Projected results provided in the Application. FEI also states that it considers $180,000 of this difference to be a sustainable reduction, as the amount represents sustainable labour savings due to integration activities in the regulatory administration and financial reporting areas that were able to be realized earlier than anticipated. FEI does not specify what these integration activities were or how they were achieved. FEI characterizes the remaining $227,000 under-expenditure as temporary savings due to a high level of staff vacancies and turnover. (Exhibit B-1-5, p. 3)

The issue of temporary vacancies creating under-spending exists in 2012 as well. For instance, in the Information Technology department the 2012 Actual results were $1.1 million less than 2012 Approved (2012 Actual of $23.442 million versus 2012 Approved of $24.5 million). FEI describes one of the reasons for the under-expenditure as follows: "A variance of $700 thousand was due to some vacant positions that were not filled and the alignment of management between FEU and FBC." (Exhibit B-1, p. 169)

Intervener Submissions and FEI Reply

CEC proposes an Opening PBR O&M Base of $223.975 million which is $5.512 million lower than FEI's proposal. CEC has taken a department-by-department approach to determine its proposal for the Opening PBR O&M Base, and its proposed adjustments differ from FEI's proposed adjustments in every department, with the exception of Customer Service, Environment Health & Safety and Finance and Regulatory Services departments. Table 3.7 shows CEC's proposed Opening PBR O&M Base:

Table 3.7 CEC's Proposed Opening PBR O&M Base ($ thousands)

	2013 Approved	Revised Sustained	2013 Sustainable	PST (Full Year)	BCUC Fees & Insurance	Pension OPEB (O&M Portion)	Pension OPEB (Retiree Portion)	Software Fees	2013 Base
Operations	$ 63,189	$ (2,512)	$ 60,677	$ 137		$ 3,667	$ 1,704		$ 66,185
Customer Service	52,452	(12,498)	39,954	18		1744	810		42,526
Energy Solutions & External Relations	18,181	(159)	18,022	23		1012	470		19,527
Energy Supply & Resource Dev.	3,738	199	3,937	7		295	137		4,376
Information Technology	25,379	(1,130)	24,249	340		691	321	(1,800)	23,801
Engineering Service & Proj. Mgmt.	16,956	(2,584)	14,372	58		1027	477		15,934
Operations Support	12,990	(1,273)	11,717	69		802	373		12,961
Facilities	9,259	305	9,564	40		146	68		9,818
Environment Health & Safety	2,999	(319)	2,680	12		123	57		2,872
Finance & Regulatory Services	14,184	(1,086)	13,098	3	923	597	277		14,898
Human Resources	8,511	(206)	8,305	22		487	226		9,040
Governance	7,935	60	7,995		93				8,088
Corporate	230	(477)	(247)	34		13	(5,851)		(6,051)
	$ 236,003	$ (21,680)	$ 214,323	$ 763	$ 1,016	$ 10,604	$ (931)	$ (1,800)	$ 223,975

(Source: CEC Non PBR Final Argument, Base O&M, p. 1)

CEC submits that "to insure the 2013 O&M amount provides a realistic representation of expenditures expected during the PBR term, care must be taken to ensure that all non-recurring O&M cost items are removed from the 2013 O&M Base." (CEC Non PBR Final Argument, Base O&M, p. 6)

With regards to the exclusion of all non-recurring O&M costs, FEI submits that:

> "non-recurring items are legitimate costs of the utility which occur in every year, although by their nature they change from year to year… Removing prudently incurred, non-recurring expenditures would underrepresent what the resources required by the utility are going into PBR. This in turn distorts the PBR plan by embedding productivity improvements in the 2013 Base O&M that are over and above the productivity included in the X-factor and stretch factor in the PBR formula." (FEI Reply Argument Non PBR, pp. 6–7)

BCPSO submits that it is reasonable to use the 2013 Actual results, which are approximately 4 million less than FEI's proposal, as a starting point for the Opening PBR O&M Base. BCPSO submits that on average over the years 2010 through 2013, the difference between what FEI has requested for O&M in its RRA and what has been approved has been approximately $4 million. This means that the Commission has reduced FEI's requested O&M by an average of $4 million in each of the past four years. BCPSO further submits that this $4 million reduction is approximately equal to the amount that FEI has classified as "unsustainable savings" when analyzing its 2013 Approved versus 2013 Actual results. (BCPSO FEI Non PBR Final Argument, p. 5)

FEI responds that the 2013 Approved amounts, referenced above by BCPSO, already reflect the reductions directed by the Commission. FEI submits that if it further reduced the Opening PBR O&M Base by the amounts proposed by CEC and BCPSO it would be removing temporary savings that resulted from factors such as hiring delays and temporary employee vacancies, and that this would result in the Opening PBR O&M Base not reflecting the resources required by FEI going into PBR. (FEI Non PBR Reply, p. 10)

BCPSO expresses concerns over the proposed Opening PBR O&M Base for the Finance & Regulatory department but provides no specific recommendation for an appropriate amount. BCPSO states that "spending is projected to be above the 5-year average" and that "this spending should be expected to decrease under PBR." (BCPSO Non PBR Final Argument, p. 6)

FEI submits: "The fact that the 2013 Approved amount for Finance and Regulatory is above the 5-year average is reflective of rising costs as discussed on pages 191-192 of the Application as approved by the Commission. The use of a 5-year average would therefore not reflect FEI's required level of resources in the base year." (FEI Reply Non PBR, p. 19)

Commission Determination

The Commission Panel agrees with FEI's approach of using the 2013 Approved O&M as the starting point for the Opening PBR O&M Base as this amount has undergone a full review through a public hearing. We further agree that it is reasonable to make adjustments for Sustainable Savings/Costs, Deferrals, and Re-classifications of O&M expenses to Capital to be reasonable. However, it is critical that sufficient rigor be applied to the establishment of the Opening PBR O&M Base in order

for the proposed I-X formula to successfully incent the achievement of efficiencies and productivity gains while still providing FEI with a reasonable opportunity to earn its allowed return.
Certain FEI statements regarding its determination of Sustained versus Temporary savings when comparing 2012 Actual and 2013 Actual results to 2012 and 2013 Approved results appear in some instances to be contradictory. These inconsistencies are particularly evident when describing costs versus savings. For instance, in response to BCUC IR 1.82.1, FEI stated: "Sustainable savings have been interpreted as lasting through the term of the PBR." However, in FEI's Reply Argument it takes issue with CEC's statement that the Opening PBR O&M Base should be set to represent expenditures expected during the PBR term. FEI submits that "… under PBR the base year costs should represent the resources required by the utility in the base year, which in this case is 2013." (FEI Non PBR Reply, p. 6)

The same inconsistencies occur in the Company's approach to temporary or non-recurring savings versus temporary or non-recurring costs. FEI states that temporary savings include "…any one time events either positive or negative that were not forecast to re-occur." (Exhibit B-11, BCUC 1.82.1) However, when describing temporary or non-recurring costs in its Reply Argument, FEI submits that since non-recurring costs are legitimate costs which occur every year, it is not appropriate to remove all of these non-recurring costs from the Opening PBR O&M Base. Thus, it can be interpreted that certain non-recurring costs are embedded in the Opening PBR O&M Base.

It appears based on FEI's description of temporary savings provided in response to BCUC IR 1.82.1 that the Company has not taken the same approach with regards to temporary or non-recurring savings as it has with temporary or non-recurring costs. FEI has not embedded temporary savings in the Opening PBR O&M Base. This is incongruous treatment between non-recurring costs and non-recurring savings. FEI submits that removing non-recurring expenditures would underrepresent its required resources going into the PBR. The same logic should be applied to non-recurring savings. Thus, by not adjusting the Opening PBR Base O&M downwards for non-recurring or temporary savings, FEI's required resources going into the PBR are over represented.

In consideration of the above, the Panel finds a further reduction to the Opening PBR O&M Base is required to embed a portion of the "temporary" or "non-recurring" savings into the Base in order to create a balance between the treatment of non-recurring costs and non-recurring savings. Based on Table 3.6 it appears that approximately $3.6 million of temporary savings have been left out of the determination of the Opening PBR O&M Base. FEI has provided a broad description of the nature of these temporary savings and has indicated in which departments these temporary savings have occurred. It is apparent from the evidence provided by FEI that temporary or non-recurring savings from employee vacancies and other employee turn-over related events exist every year for a variety of reasons and in a variety of departments. Even if certain vacancies are filled in one department there will likely be issues with staffing in other departments. Therefore, even if the specific reason for the temporary savings changes each year, the savings still exist in one form or another. Thus, in the Panel's best judgment, it is appropriate to embed $1 million of the $3.6 million Temporary savings in the Opening PBR O&M Base. Accordingly, the Panel directs that the 2013 Base O&M be reduced by $1 million. This is in addition to any further changes directed in this Decision. This is consistent with FEI's approach to classifying costs, as it has stated that certain non-recurring costs occur every year and thus should not be removed from the Opening PBR O&M Base.

While the Panel does not consider it necessary to review each of FEI's O&M departments in the level of detail provided in FEI's previous RRA Decision or in the level of detail explored by the CEC, the Panel has identified the Energy Solutions & External Relations department as requiring further examination and adjustment. This is discussed in the subsequent section.

3.1.2.1 Energy Solutions & External Relations Department

FEI proposes an Opening PBR O&M Base for the Energy Solutions & External Relations (ES&ER) department of $19.215 million. This is $193,000 higher than the 2013 Actual spend of $19.022 million and $1.034 million higher than the 2013 Approved amount of $18.181 million. (Exhibit B-54, BCUC Panel 1.3.2, p. 17; Exhibit B-1-5, Attachment 5, p. 4; Exhibit B-1, Section C3, p. 158)

FEI classified the difference between the 2013 Actual amount and the proposed Opening PBR O&M Base amount of $193,000 as "temporary in nature". FEI stated that the reason for the difference is "primarily due to lower incentive spending on the High Carbon Fuel Switching program which is dependent on customer participation." However, FEI further stated that "[w]hile customer participation may vary by year, it is beyond FEI's control and the 2013 Approved level of funding for this program reflects the approved envelope of funding that FEI should maintain as being available for participants. The 2013 Approved amount is therefore more appropriate to include in the 2013 Base O&M, than the 2013 Actual amount." (Exhibit B-54, BCUC Panel 1.3.2)

Tables 3.8 and 3.9 show the breakdown of 2012 ES&ER approved versus actual spending and 2013 ES&ER approved versus projected spending:

Table 3.8 2012 Approved vs. 2012 Actual ES&ER Spending ($ thousands)

BCUC Reference	Particulars	2012 Approved ($000's)	2012 Actual ($000's)	Difference	Explanation of Significant Differences	Temporary or Sustainable
310-11	ES&ER Supervision	622	614	8	-	-
310-12	Energy Solutions	5,040	5,134	(94)	-	n/a
310-13	Energy Efficiency	120	117	3	-	n/a
310-14	Communications & External Relations	6,441	7,212	(771)	Incremental spend due to natural gas customer education and awareness	Sustainable This activity has continued into 2013 at the same levels, and is critical in order to increase demand for natural gas end-use.
310-15	Forecasting, Market and Business Development	5,286	4,998	288	Lower spend due to short term vacancies which are not sustainable in the long run	Temporary
310-10	**Total ES&ER**	**$17,509**	**$18,075**	**(566)**		

(Source Exhibit B-24, BCUC 2.279.1, p. 120)

Table 3.9 2013 Approved vs. 2013 Actual ES&ER Spending ($ thousands)

BCUC Reference	Particulars	2013 Approved* ($000's)	2013 projection ($000's)	Explanation of Significant Differences	Explanation of any Difference	Temporary or Sustainable
310-11	ES&ER Supervision	796	671	125	Offset in Energy Solutions	n/a
310-12	Energy Solutions	4991	5,117	(126)	Offset in ES&ER Supervision	n/a
310-13	Energy Efficiency	120	301	(181)	Increased spend in High Carbon Fuel Switching Program	Sustainable This program will continue at this level to influence customers to switch from high carbon fuels to natural gas
310-14	Communications & External Relations	6155	6,988	(833)	Increased spend in natural gas customer education and awareness program	Sustainable This activity is expected to continue throughout the five year period to increase customer awareness of the benefits of natural gas and in order to increase demand for natural gas end-use
310-15	Forecasting, Market and Business Development	6119	6,138	(19)	-	n/a
310-10	**Total ES&ER**	**$18,181**	**$19,215**	**($1,034)**		

(Source: Exhibit B-24, BCUC 2.279.2, p. 121)

In the 2012–2013 FEU RRA, the Commission approved an incremental spending amount of $400,000 in 2012 and a further incremental amount of $200,000 in 2013 related to the Long Term Resource Plan (LTRP). FEI stated that it "expects to file the completed LTRP later this year and will continue such compliance throughout the 2014–2018 forecasted period with an updated LTRP to be filed during this five year period." (Exhibit B-11, BCUC 1.99.1)

FEI submitted:

> "The LTRP process is an ongoing one. While FEI has undertaken many improvements to the LTRP currently being prepared as a result of the increased funding, there are still more improvements to make among those outlined in the 2012-2013 RRA proceeding in future LTRP's, both in the area of energy demand forecasting and in other areas of LTRP analyses and reporting. As such, the current level of funding directed toward LTRP related activities remains appropriate." (Exhibit B-24, BCUC 2.282.5)

Intervener Submissions and FEI Reply

CEC submits that the appropriate Opening PBR O&M Base for ES&ER is $18.022 million, which is $159,000 less than 2013 Approved and $1.193 million less than FEI's proposed Opening PBR O&M Base for ES&ER. (CEC Non PBR Final Argument, Base O&M, p. 16)

CEC submits that there should be a reduction of $1 million related to labour to reflect employee vacancies which were not filled. CEC further submits that the Opening PBR O&M Base for ES&ER should be reduced by an additional $193,000 which is the difference between FEI's 2013 Projected and 2013 Actual ES&ER O&M. FEI has attributed the $193,000 to temporary savings, but CEC submits that this amount should be considered sustainable savings. (CEC Non PBR Final Argument, Base O&M, p. 16)

FEI responds that it is not appropriate to draw a connection between labour savings in the ES&ER department in the manner proposed by CEC because the $9.4 million labour savings identified by FEI in the Application are not primarily related to the ES&ER department. Therefore, FEI submits that CEC's proposed reduction would "double-count the labour savings already included in the 2013 Base O&M, resulting in a gratuitous and arbitrary reduction to the 2013 Base O&M." (FEI Reply Non PBR, p. 13)

Commission Determination

FEI proposes an Opening Base O&M for the ES&ER department of $19.215 million, which is $1.034 million higher than the 2013 Approved amount. The Panel has previously agreed to a methodology to establish the Base O&M. This methodology starts with 2013 Approved amounts and adjusts those amounts where warranted. FEI has added an additional $1.034 million to the 2013 Approved amount for increased spending in areas such as the High Carbon Fuel Switching Program and the Natural Gas Customer Education and Awareness Program. The Commission has previously approved levels of spending for these programs and FEI has not provided sufficient justification for an increased level of spending. **Accordingly, the Commission Panel directs FEI to reduce the ES&ER Opening Base amount by $1.034 million.**

As part of the 2012–2013 FEU RRA, the Commission approved incremental funding for numerous initiatives, including the Long Term Resource Plan. The Panel is unconvinced that the level of incremental spending approved for the LTRP in the 2012–2013 FEU RRA Decision should remain in place going into the PBR period. We recognize that some LTRP work is ongoing, as has been the case for past LTRPs. However, the Panel does not consider it reasonable to approve the incremental spending that was approved in the 2012–2013 FEU RRA Decision. This is because the next LTRP is not expected to be in front of the Commission for another five years. **The Commission Panel therefore directs FEI to further reduce the Base O&M for the LTRP by $600,000.**

3.1.2.1.1 Political Donations

In the 2012-2013 FEU RRA Decision, the Commission determined that community involvement funding costs should be "allocated 50 percent to the ratepayer and 50 percent to the shareholder." Included in the 2012–2013 community involvement costs are donations to political parties of $42,450 in 2012 and $50,000 projected in 2013. (2012–2013 FEU RRA Decision, p. 73; Exhibit B-11, BCUC 1.108.1) FEI stated that the costs of FEI contributions to political parties are recovered from ratepayers and are included in the 2013 Base O&M that will be escalated by the O&M formula (Exhibit B-11, BCUC 1.108.2).

The treatment of donations to political parties in the 2012-2013 FEU RRA Decision differs from the treatment in the 2012-2013 FBC RR and 2012 ISP Decision. In the 2012-2013 FBC RRA and 2012 ISP Decision, the Commission stated that "contributions to political parties should be solely for the account of the shareholder" (pp. 67–69).

FEI submits that political donation amounts are small compared to the total revenue requirement and that it has followed the same approach as the previous revenue requirement where $50,000 of political donations was approved (T1:54).

There were no Intervener submissions on this issue.

Commission Determination

The Commission Panel is of the view that the size of the amounts of the donation is not the issue. The issue is whether it is appropriate for a utility to be making political donations with the expectation that the cost of these be recovered from the ratepayer. There is no justification provided as to why political donations are required in order to provide safe, reliable and adequate service to ratepayers. Therefore, **the Commission Panel directs contributions to political parties to be solely on the account of the shareholder.**

3.1.2.1.2 Biomethane

In Commission Reasons for Decision and accompanying Order G-210-13 dated December 11, 2013 for the FEI Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis (2013 Biomethane Decision) the Commission directed that all interconnection and Biomethane Program Costs are to be recorded in the Biomethane Variance Account (2013 Biomethane Decision, p. 65). In the 2012 Biomethane Decision the Commission emphasized that all overhead costs related to the Biomethane Program should be included in this allocation. (2013 Biomethane Decision, p. 46) In FEI's February 2014 Evidentiary Update FEI updated its 2013 Base O&M to take into account the 2013 Biomethane Decision (Exhibit B-1-5, p.7). On page 8 of the Evidentiary Update FEI states:

> "The removal of $410 thousand in Biomethane program O&M from the 2013 Base for the formula, which is now included as a flow-through item outside of the formula. The 2014 forecast O&M is $590 thousand as shown in Section B, Table B6-5. Of this amount, $570 thousand is transferred to the BVA as shown

on Schedules 15 and 18 of Section E Financial Schedules. Approximately $20 thousand remains in the gross O&M for recovery through delivery rates because this O&M is associated with the existing approved seven interconnection projects;" (Exhibit B-5-1, p. 8)

FEI states it has the equivalent of one Full Time Equivalent (FTE) managing the Biomethane Program (Exhibit B-24, BCUC 2.250.2).

Commission Determination

The Commission Panel directs that costs associated with the equivalent of one FTE in the ES&ER group be removed from the 2013 Base Year O&M.

The Commission Panel directs FEI to include in the Compliance Filing a detailed breakout of the costs, including the labour component, that are included in the total of $410,000 of actual Biomethane Program O&M incurred in 2013 and therefore, removed from the 2013 Base Year and a detailed breakdown of the total of $570,000 of forecast Biomethane O&M costs that are transferred to the Biomethane Variance Account for the 2014 year. FEI is to provide the O&M cost breakdown at the level of detail shown in the Table J-2 in Appendix B1 of the 2012 Biomethane Application.

3.1.2.2 Executive Compensation and Short Term Incentive Plan

The Panel has made a number of determinations in the FBC 2014-2018 Decision with respect to the Short Term Incentive Plan (STIP) component of executive compensation. Given that the executive team is the same for FBC and FEI, the Panel finds the same reasoning should apply to FEI. The Panel directs that the following determinations made in the FBC 2014-1018 RRA Decision are to apply to FEI STIP payments:

> "**The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and must reduce its O&M Base accordingly…**

> **Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder…**
>
> In summary, FBC is to calculate the STIP payment based on the target median and then deduct 30 percent of this calculation to arrive at the amount to be borne by the ratepayer…" (FBC 2014-2018 RRA Decision, Section 3.1.2.3)

As part of its Compliance Filing, FEI is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount which would have been spent if only the target STI had been met (as per Page 9 of the Executive Compensation Benchmarking, Exhibit B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M.

3.1.3 Determining the Base Capital

The Commission Panel has previously determined that further review of the capital exemption threshold is required. The Panel is mindful of this potential upcoming change and also of the amalgamation, which is expected to take effect at the outset of 2015. A base capital adjustment will be required for the 2015 and possibly also for 2016. Accordingly, the Panel will review FEI's proposed capital spending in order to determine a base which is applicable only to the calculation of 2014 revenue requirements.

Table 3.10 shows FEI's proposed capital spending during the PBR term.

Table 3.10 Forecast FEI Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,225	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains & Service Renewals & Alt.	22,556	25,815	24,433	28,245	34,059	34,304
Total Sustainment Capital	78,065	78,449	79,045	77,198	80,578	82,340
Growth Capital						
New Customer Mains	6,783	5,374	5,462	5,561	5,664	5,798
New Customer Services	13,471	18,360	19,502	20,214	20,337	20,363
New Customer Meters	2,197	1,664	1,805	1,876	1,877	1,862
Total Growth Capital	22,451	25,398	26,769	27,651	27,878	28,022
Other						
Equipment	5,840	6,818	7,328	7,127	7,358	6,702
Facilities	4,194	3,904	4,026	4,122	4,269	4,626
IT	20,107	20,105	20,105	20,106	20,102	20,098
Total Other	30,141	30,828	31,460	31,354	31,729	31,425
Total Gross Capex	130,657	134,675	137,274	136,203	140,185	141,788
CIAC	(5,492)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)
Total Net Capex	125,165	128,854	131,454	130,382	134,366	135,969

(Exhibit B-1-5, Attachment 5, Table C4-3)

The average net forecast annual capital spending for 2014 and 2015 is $130.153 million, compared to 2013 Approved of $116.283 million.

For the base capital to be used in the PBR capital formula, FEI proposed a total net capital amount of $125.165 million (FEI Exhibit B-1-5, Attachment 5, Table C4-2). The difference between the 2013 Approved and the Proposed Base Capital are adjustments related to PST, Pension, Vehicles and IT Capital.

CEC provided the following comments on FEI's proposed base capital:

1. **Sustainment Capital** – CEC submits that the requirement to have the current level of sustainment capital expenditures embedded in the PBR term is not fully justified. In

support, it argues that FEI's expenditure history shows that FEI began to pro-actively replace or upgrade assets in 2008, but by 2015 and 2016 these amounts are forecast to decrease in every class except Distribution Mains and Service Renewal Alterations. It further submits that this is "the result of FEI's successful efforts, since 2008, in reducing the inventory of assets nearing the end of their useful life" (CEC Non PBR Final Argument, p. 9).

2. **Growth Capital** – CEC submits that there are many factors influencing growth capital that are outside of FEI's control and accordingly does not recommend any changes (CEC Non PBR Final Argument, pp. 10–11).
3. **Other Capital** – CEC notes that the 2013 approved IT capital amounts for all categories except for Infrastructure Sustainment are higher by at least 20 percent than the actual expenditures since 2007. It further submits that FEI has prepared a list of IT projects for execution in 2013 but not 2014. In its view, the 2013 capital base should be reduced by $3 million (CEC Non PBR Final Argument, p. 12).

Commission Determination

Given the upcoming amalgamation a rebasing of capital will be required for 2015. Further, given the Panel's directives concerning excluded capital, a further rebasing will in all likelihood be required for 2016. The Panel acknowledges CEC's concerns and expects they will be given consideration in those proceedings.

FEI's proposed 2013 Base Capital is based on 2013 Approved amounts and this is consistent with the approach to the O&M Base**. Accordingly, the Panel approves FEI's proposed 2013 Base Capital, for use in determining formulaic 2014 capital, as applied for, subject to any further change directed in this Decision.**

3.2 Accounting Policies

FEI seeks a number of approvals related to accounting policy changes effective January 1, 2014. These requests are discussed in the following sections.

3.2.1 Discontinuance of US GAAP to Canadian GAAP Reconciliation

FEI requests approval to discontinue its requirement to provide a reconciliation of US GAAP to Canadian GAAP in its annual reports to the Commission.

Pursuant to Order G-117-11, the Commission approved FEI to adopt US GAAP for regulatory and accounting purposes effective January 1, 2012. As part of that Order, the Commission requested an annual reconciliation from US GAAP back to Canadian GAAP.

FEI states that it no longer maintains specific accounting records in compliance with pre-2012 Canadian GAAP since they are not used for any other reporting purpose; therefore, it is becoming increasingly complicated to complete the reconciliation on a prospective basis (Exhibit B-1, p. 264). Additionally, FEI submits that this reconciliation could be misleading due to the fact that pre-2012 Canadian GAAP no longer exists as a financial reporting option and thus is no longer updated to reflect potential changes in accounting guidance. This results in a reconciliation that has limited comparative value. (FEI Non PBR Final Argument, p. 47)

FEI estimated that it takes approximately one week to prepare this reconciliation and that continuing to prepare this reconciliation is expected to not only increase the future preparation and review time of its BCUC annual reports but that it also increases FEI's external actuarial costs. FEI submitted that it would agree to provide and communicate accounting policy changes as part of its Annual Review material, consistent with what was provided during the previous PBR term. (Exhibit B-24, BCUC 2.316.1)

No Interveners commented on this request.

Commission Determination

The Commission Panel approves FEI's request to discontinue the US GAAP to Canadian GAAP reconciliation in future BCUC Annual Reports. The reconciliation is of limited use going forward due to the fact that the reconciliation relates to pre-2012 Canadian GAAP. In addition, continuing with this reconciliation creates unnecessary additional regulatory burden for FEI.

The Panel directs FEI to communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period.

3.2.2 Allocation of Retiree Pension and OPEBs

FEI requests approval to include both the current service and retiree portion of pension and OPEBs in benefit loadings. This proposed treatment is consistent with FEI's practice prior to 2010. FEI changed its policy in 2010 in anticipation of adopting International Financial Reporting Standards (IFRS), as IFRS only allows for the capitalization of direct expenditures into benefits loadings and capital. However, FEI instead adopted US GAAP starting January 1, 2012 and states that it plans to continue using US GAAP as the basis for financial and regulatory accounting during the PBR period. (Exhibit B-1, p. 265)

The impact of this proposed accounting change is a reduction to FEI's 2013 Base O&M of $930,000 and a corresponding increase to FEI's 2013 Base Capital of the same amount. (Exhibit B-1-5, Attachment 5, Table C3-2, p. 4)

FEI stated: "As a result of further investigation into specific US GAAP guidance and further understanding of general industry practice, the Company believes that the full Net Benefit Cost (which includes both the Current Service Cost and other components of pension expense, including retiree portion of pension and OPEBs) is the appropriate amount to be included in benefit loadings." (Exhibit B-11, BCUC 1.164.1)

When asked if this proposed accounting change has been reviewed and signed off on by FEI's independent auditors, FEI stated: "No… If the BCUC approves FEI recognizing the full net benefit cost of pension and OPEB in benefit loadings, FEI anticipates that the auditors will accept the change in accounting treatment since US GAAP, in many cases, allows for consistency with the economic substance of the regulator's actions." FEI further submitted that it has the same auditors as those for its sister company, FBC, and the auditors have reviewed and accepted this accounting treatment for FBC. (Exhibit B-24, BCUC 2.317.2)

Commission Determination

The Commission Panel approves FEI's request to include the retiree portion of pension and OPEB expenses in benefit loadings for O&M and Capital. This treatment is consistent with FEI's practice prior to 2010 and is allowable under US GAAP. Given that FEI submits that it plans to continue reporting under US GAAP for financial and regulatory accounting purposes during the term of the PBR, the Panel considers it reasonable for FEI to revert back to its previous treatment of pension and OPEB expenses.

3.2.3 Capitalization of Annual Software Costs

FEI requests approval to adopt a capitalization methodology for the treatment of annual software costs paid to vendors in support of upgrade capability. The impact of this capitalization methodology is a reduction to FEI's 2013 Base O&M of $1.8 million and a corresponding increase to Base Capital. (Exhibit B-1, p. 265) For 2013, $4.2 million is being paid for annual software costs (Exhibit B-24, BCUC 2.318.8, p. 280). Therefore, under the new methodology approximately 43 percent of annual software costs would be capitalized.

FEI submitted that the proposed treatment is consistent with US GAAP because US GAAP allows for costs associated with upgrades to be capitalized when the upgrades result in either enhanced functionality of the software or extension to the useful life of the existing software (Exhibit B-11, BCUC 1.165.1).

FEI further submitted that it has estimated the allocation of capitalized software costs based on a combination of the expected benefits to be derived from the software and the feedback provided by its external vendors. It further submits that based on information provided by the vendors, it is estimated that at least 50 percent of the total annual fees add value and extend the life of the respective software asset and should be capitalized. (Exhibit B-11, BCUC 1.165.5)

FEI stated that this proposed capitalization methodology has not been reviewed and signed off on by FEI's external auditors. However, FEI submits that it does not anticipate the auditors will have an issue with the proposed change since it is consistent with the treatment employed by FBC. (Exhibit B-24, BCUC 2.318.2)

FEI submitted that this change in methodology was proposed because it "results in an allocation of O&M and capital that more accurately reflects the capital nature of Annual Software Costs and is better aligned with US GAAP" (Exhibit B-24, BCUC 2.318.5).

Commission Determination

The Commission Panel denies FEI's request to capitalize annual software upgrade costs. The Panel directs FEI to adjust its 2013 Base O&M and Capital to add the $1.8 million in annual software upgrade costs back to 2013 Base O&M and to remove this amount from 2013 Base Capital.

The Panel is not persuaded that it is appropriate to capitalize annual software upgrade costs. FEI submits that although the proposed change is not required by US GAAP, the change is better aligned with US GAAP guidance because the upgrades result in either enhanced functionality of the software or extension to the useful life of the existing software. The Panel recognizes that there may be components of the annual software costs which extend the useful life of the asset. However, costs of this nature which occur every year are more appropriately expensed in the year they are incurred. This prevents additional costs being borne by ratepayers through the recovery of FEI's return on rate base related to the capitalized software costs. Given that FEI proposes to capitalize almost 50 percent of these software costs each year, the accumulating impact of the capital additions would result in higher costs to ratepayers each year. The Panel also notes that there are likely other types of repair and routine maintenance activities that could be considered to have benefits that extend beyond the period in which the expenses are incurred, yet those expenses are typically not capitalized.

3.2.4 Purchase of Vehicles

FEI requests approval to switch from its current policy of leasing its fleet of vehicles to purchasing vehicles. Pursuant to this request, FEI is requesting approval to depreciate these purchased vehicles at a rate of 12.5 percent based on asset class 484 Vehicles.

FEI states that while it currently acquires the majority of its fleet from a third party lessor, the other utilities (FEVI, FEW and FBC) purchase their vehicles. FEI submits that a consistent treatment of how vehicles are acquired would simplify business processes within the fleet and other support departments. FEI notes that the change from leasing to purchasing vehicles does not change the regulatory treatment because the existing vehicle lease is treated as a capital lease for financial and regulatory purposes; thus, the only resulting change is that what was previously shown as a capital addition will now be shown as a capital expenditure. (Exhibit B-1, pp. 265–266)

FEI submits that based on its financial analysis, it should transition the vehicle fleet to an owned status as the current leased vehicles are retired because this option has the lowest present value cost of service (approximately $3 million over a 20 year analysis period) (Exhibit B-11, BCUC 1.166.6).

FEI anticipates retiring between 43 and 48 vehicles per year during the five year PBR term (Exhibit B-11, BCUC 1.166.11). Additionally, FEI submitted that there will be no change in the maintenance plan for the purchased vehicles and that the maintenance plan is based on vehicle type and is identical for leased vehicles and purchased vehicles (Exhibit B-24, BCUC 2.319.5, p. 283).

No Interveners commented on this request.

Commission Determination

The Commission Panel approves FEI's request to switch from its current vehicle leasing program to transition to a purchased vehicle fleet. The Commission Panel further approves a depreciation rate of 12.5 percent for asset class 484 Vehicles.

The Panel has reviewed FEI's financial analysis and accepts that its proposal to transition the vehicle fleet to an owned status has the lowest present value cost of service. The Panel also agrees that this change will likely simplify business processes within the fleet and other departments, and we note that there will be no change in regulatory treatment as a result of this new policy.

3.2.5 Capitalized Overhead

FEI's currently approved overhead capitalization rate is 14 percent, which was approved as part of the 2010–2011 Terasen Gas Inc. (TGI) Negotiated Settlement Agreement pursuant to Order G-141-09. In the 2012–2013 FEU RRA, the Commission accepted FEI's proposal to keep the capitalized overhead rate at 14 percent; however, the Commission directed FEI to update its capitalized overhead methodology and to obtain a report on this methodology from a qualified independent third party for inclusion in its next revenue requirement.

FEI has therefore included the KPMG Capitalized Overhead Report in Appendix F3 of the Application (Exhibit B-1-1). The KPMG report yielded two recommendations for an appropriate capitalized overhead rate based on two different estimating methods – the "Survey-Based Approach" and the "Mathematical-Based Approach." The Survey-based approach yielded a recommended capitalized overhead rate of 12 percent, and the Mathematical-based approach yielded a recommended rate of 11 percent.

The capitalized overhead report states that KPMG finds the Survey-based cost allocation methodology to be a "reasonable basis" for determining the overhead capitalization rate. The report further states: "In the absence of future significant regulatory, accounting and organizational changes, the application of this rate in future periods may continue to be appropriate." (Exhibit B-1-1, Appendix F3, p. 5)

FEI proposes to keep its capitalized overhead rate at 14 percent due to the fact that there has been no material change in utility operations since its last RRA. Additionally, FEI submits that it is expecting forecast net capital expenditures for the PBR period to remain at levels that are higher than the 2010–2013 period. FEI also states that its current overhead capitalization approach is consistent with other Canadian and US utilities and its rate is reasonable and within a range of other utilities surveyed by the Company. (FEI Non PBR Final Argument, p. 58)

FEI estimated that the impact on delivery rates is 0.4 percent for every 1.0 percent change in the other direction in the Capitalized Overhead rate. Therefore, reducing the Capitalized Overhead rate from 14 percent to 12 percent would increase customer delivery rates by approximately 0.8 percent. (Exhibit B-11, BCUC 1.167.1)

BCPSO states that the results of the KPMG study suggest that FEI's overheads capitalized rate is 2to 3 percent higher than it should be (BCPSO Non PBR Final Argument, p. 4).

FEI submits that the survey-based approach is "subjective in nature" and that KPMG's use of the word "estimate" when recommending the capitalized overhead rate of 12 percent suggests that this rate is "indicative in nature, but not definitive" (FEI Non PBR Final Argument, pp. 57–58).

No other Interveners commented on FEI's capitalized overhead rate.

Commission Determination

The Commission Panel directs FEI to reduce its capitalized overhead rate to 12 percent. The Panel has reviewed the KPMG report and agrees that based on the results of the survey-based approach, a capitalized overhead rate of 12 percent is appropriate. Utilizing the rate recommended by FEI's external auditors is reasonable. The Panel recognizes that reducing the capitalized overhead rate will result in an increase to customer delivery rates but notes that this increase to delivery rates amounts to less than 1.0 percent. Further, the Panel notes that setting the appropriate capitalized overhead rate is important to help prevent the occurrence of inter-generational inequity issues.

3.2.6 Modification to Lead/Lag Days for Cash Working Capital

FEI requests approval to modify its approved Lead/Lag days for cash working capital to remove HST and Residential Energy Credit lead days from the cash working capital calculation and instead use GST and PST lead days. The PST and GST lead days are the same as those approved in Commission Order G-141-09 prior to the introduction of the HST. FEI states that the impact of this modification does not materially impact the cash working capital or the cost of service. (Exhibit B-1, p. 266)

No Interveners commented on this request.

Commission Determination

The Commission Panel approves FEI's request to modify the Lead/Lag days for cash working capital as outlined in the Application. These modifications are appropriate given the conversion back to PST/GST from HST as mandated by the Provincial Government.

3.2.7 Changes to Depreciation Methodology

FEI is proposing two changes related to depreciation:

1. Calculate depreciation expense commencing at the beginning of the year following when the asset is placed into service (as compared to the current practice of depreciation commencing at the time the asset is placed into service).
2. Discontinue the Depreciation Variance deferral account.

(FEI Non PBR Final Argument, p. 52)

This proposed method for calculating depreciation was approved by the Commission as part of the 2004–2007 PBR RRA. FEI then requested approval to change to its current depreciation method as part of the 2010–2011 RRA in order to comply with IFRS, as at that time the adoption of IFRS was anticipated.

FEI submits that the proposed depreciation method is more appropriate for the following reasons:

(i) The current depreciation method with the accompanying deferral account undermines the incentive to find efficiency savings in capital due to the fact that any variances between forecast and actual depreciation expense would be flowed through to ratepayers;

(ii) The proposed method facilitates the proper functioning of the PBR plan because it allows the depreciation expense to be driven by formula versus actual capital spending from prior years, as opposed to the timing of when assets are placed into service in the current year;

(iii) The proposed method is consistent with US GAAP;

(iv) The proposed method is simpler due to the discontinuance of the Depreciation Variance deferral account.

(FEI Non PBR Final Argument, pp. 52–53)

The impact of the change in depreciation method is that depreciation expense will be reduced for 2014 by approximately $3.3 million, which FEI submitted equates to a delivery rate decrease of approximately 0.7 percent in 2014 (Exhibit B-24, BCUC 2.321.3).

The Depreciation Variance deferral account was approved pursuant to Order G-44-12 for use during the 2012–2013 test period only. The purpose of this deferral account was to minimize variances in actual and forecasted depreciation expense related to the timing or amount of capital being placed into service as compared to forecast. However, this deferral account is not necessary under FEI's proposed depreciation methodology. Since the Depreciation Variance deferral account was only approved for the 2012–2013 test period, FEI has not included a request for discontinuance of the deferral account as part of the Application.

No Interveners commented on this request.

Commission Determination

The Panel approves FEI's request to change its method of calculating depreciation expense whereby depreciation expense commences at the beginning of the year following when the asset is placed into service. The Panel notes that as a result of this approval, FEI's use of the Depreciation Variance deferral account will be discontinued. The Panel agrees that the requested changes to the calculation of depreciation expense facilitates the proper functioning of the PBR Plan and that the revised method is simpler to administer due to the elimination of the Depreciation Variance deferral account.

3.2.8 Shared and Corporate Services

3.2.8.1 FEI Shared Services Allocation to FEVI and FEW

FEI requests approval for its allocation of costs to each of FEVI and FEW as determined by its Shared Services Agreements.

In the 2012–2013 FEU RRA Decision, the Commission directed FEI to "update both the Corporate and Shared Service Agreements for inclusion in their next revenue requirements application (p. 71).

FEI states: "Since FEI completed a review of the Shared Services agreement and cost allocation approach as part of the 2010–2011 RRA with validation by KPMG, no changes in methodology have occurred since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place." (Exhibit B-1, Section D3, p. 278)

FEI provides the following comparative information of shared services amounts among FEU:

Table 3.11 Shared Service Cost Allocation Amongst FEU ($ thousands)

('000s)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Allocated to FEVI	5,104	5,477	5,793	7,255	7,550	8,439	8,995	9,399	9,630
One time adjustment						600			
Allocated to FEW	-	-	-	192	197	196	250	246	255
One time adjustment						16			
Allocated to FEI	45,470	47,754	50,289	65,187	67,900	76,000	77,863	83,713	86,547
One Time adjustment						(616)			
Total Costs Included in Shared Services Pool	50,574	53,231	56,082	72,634	75,647	84,635	87,108	93,358	96,432
Direct Costs Retained by FEI	133,503	137,985	141,657	141,331	145,706	144,282	158,140	147,905	144,438

(Source: Exhibit B-24, BCUC 2.327.1)

FEI submits that the 2013 Base Year allocation to FEVI is $600,000 higher than 2013 Approved for the following reasons:

(a) Increased annual resources of $200,000 are required in the dispatch centre to plan and coordinate field resource requirements;

(b) $200,000 is related to the true-up of FEVI's share of FEU's directed $4 million O&M productivity factor from the 2012–2013 RRA Decision;

(c) $200,000 is related to the impact of pension/OPEB and accounting related changes.

(Exhibit B-1, p. 279)

The cost allocation drivers used in the allocation methodology are the number of employees and the number of customers. For shared services costs allocated by number of employees, based on

2012 figures, FEI is allocated 92.2 percent of costs, FEVI is allocated 7.7 percent of costs, and FEW is allocated 0.1 percent of costs. For shared services costs allocated by number of customers, based on 2012 figures, FEI is allocated 90 percent of costs and FEVI is allocated 10 percent of costs. (Exhibit B-1, pp. 279–280)

No Interveners commented on the allocation of shared services in their Final Arguments.

Commission Determination

The Panel approves the allocation of shared services costs between FEI and FEVI and the allocation of shared services costs between FEI and FEW as outlined in the Application.

The Panel notes that FEI did not comply with the Commission's directive in the 2012–2013 FEU RRA Decision to update its Shared Service Agreements. FEI states in its Application that "no changes in methodology have occurred since the time of the 2009 review that would warrant making any change to the Shared Service Agreement currently in place." Regardless of whether FEI considers it warranted to make changes to the Shared Service Agreements, the fact remains that the Commission in the previous RRA Decision deemed it necessary and directed changes to be made accordingly.

However, the Panel also recognizes that commencing in 2015 the issue of allocation of shared services costs amongst FEI, FEVI and FEW will no longer exist due to the amalgamation of the FEU. Given the impending amalgamation and the fact that there appears to be little change to the interactions between FEI and FEVI or FEI and FEW, the Panel considers it no longer necessary for FEI to update its Shared Service Agreements to comply with the 2012–2013 FEU RRA Decision.

3.2.8.2 Allocation of Executive Cross Charges

FEI requests approval to allocate executive cross charges between itself and FBC using the Massachusetts formula instead of the Time Estimate method used in previous years whereby management made estimates of time allocations using time sheets. (FEI Non PBR Final Argument, p. 55)

FEI submits that the Massachusetts formula is well established and generally accepted in British Columbia and other regulatory jurisdictions. FEI also submits that use of the Massachusetts formula will allow for a more "streamlined and efficient approach of allocating the costs, while ensuring an appropriate and transparent allocation methodology." (FEI Non PBR Final Argument, p. 55)

The Massachusetts Formula is already used to allocate corporate costs from FortisBC Holdings Inc. (FHI) to FEU. Additionally, Board of Directors costs have been allocated from FHI to FEI and FBC using the Massachusetts formula since 2010. (Exhibit B-24, BCUC 2.329.4)

Table 3.12 shows the increase/(decrease) in costs allocated to FEI for the years 2010 through 2013 if the Massachusetts Formula were used instead of the currently approved Time Estimate methodology (note: Table is in $ thousands):

Table 3.12 Impact of Applying Massachusetts Formula

	2010 Actual	2011 Actual	2012 Actual	2013 YTD*	2013 Projection
Increase (Decrease) in Executive Labour cross-charges to FEI from applying Massachusetts Formula instead of Time Estimate allocation	$ (42)	$ 5	$ 193	$ 165	$ 198

**through to the end of October 2013*

(Source: Exhibit B-24, BCUC 2.329.7)

Based on Table 3.12, it appears there will be an approximate increase of $200,000 allocated to FEI under the Massachusetts Formula and a resultant decrease of $200,000 allocated to FBC in 2013. FEI submits that the difference going forward into the PBR period is not expected to be materially different on overall O&M expense. (Exhibit B-24, BCUC 2.329.7)

No Interveners commented on the proposed change in allocation of executive cross charges in their Final Arguments.

Commission Determination

FEI's request to allocate executive cross charges between FEI and FBC using the Massachusetts Formula is approved. The Panel accepts that this method simplifies and streamlines the allocation of executive time between FEI and FBC and it recognizes the high level of integration between the two companies at the executive level.

The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.

3.2.8.3 Allocation of Corporate Services

FEI requests approval of the allocation of costs for corporate services between itself and FHI, as reflected in the Corporate Services Agreements and as outlined in the Application. (Exhibit B-1-5, Appendix J).

FHI is responsible for providing key corporate functions directly to FEU. FHI allocates the corporate services costs to FEI, FEVI and FEW using the Massachusetts Formula, which is the same allocation methodology previously approved by the Commission. Table 3.13 shows the allocation of FHI to FEI, FEVI and FEW.

Table 3.13 Allocation of Corporate Services

Mgmt Fee Recovery	2010 Actual	2011 Actual	2012 Actual	2013 Projected	2013 Approved
(000s)					
FEI	9,556	9,652	10,718	11,031	11,031
FEVI	1,087	1,097	1,140	1,196	1,196
FEW	49	49	49	50	50
Total - FEU	10,692	10,798	11,907	12,277	12,277
Other	905	2,211	1,052	146	961
	11,597	13,009	12,958	12,423	13,238

(Source: Exhibit B-1, Table D3-7, p. 286)

FEI submits that the fees to all entities are expected to increase by inflation in 2014 and beyond. (Exhibit B-1, Section D3, p. 285)

FEI engaged the independent public accounting firm KPMG to review the corporate services cost allocation methodology and the reasonability of the costs of the corporate services provided by Fortis Inc. (FI) to FHI and by FHI to FEI. The KPMG report was included as Appendix F2 to the Application (Exhibit B-1-1). As a result of the review, KPMG concluded that the allocation methodology and costs are reasonable. (Exhibit B-1-1, Appendix F3, p. 4)

No Interveners commented on the allocation of corporate services in their Final Arguments.

Commission Determination

The Panel approves the allocation of corporate services costs between FHI and FEI, as reflected in the Corporate Services Agreements between FHI and FEI and as outlined in the Application. The Panel acknowledges that the corporate services allocation methodology and costs have been reviewed and found to be reasonable by the independent public accounting firm KPMG. These costs and the allocation methodology remain unchanged from what was approved in the 2012–2013 FEU RRA and thus have been subject to a high level of scrutiny through a public hearing process.

3.3 Deferral Accounts

FEI requests approval to create, modify and discontinue various deferral accounts, as well as approval to amortize and dispose of balances of various deferral accounts. The comprehensive list of deferral accounts subject to approval requests are listed in tabular form in the draft order provided by FEI in the February 21, 2014 Evidentiary Update. (Exhibit B-1-5, Appendix J)

No Interveners commented on FEI's deferral account requests.

3.3.1 New Deferral Accounts

FEI requests approval to establish the following two new rate base deferral accounts:

(i) 2014–2018 PBR Application Costs deferral account; and

(ii) TESDA Overhead Allocation Variance deferral account.

2014-2018 PBR Application Costs Deferral Account

The costs incurred in 2013 and 2014 related to this Application are proposed to be placed in the 2014-2018 PBR Application Costs deferral account. These costs include legal fees, costs for expert witnesses and consultants, costs related to independent studies, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. FEI proposes to amortize this deferral account over five years commencing January 1, 2014, as it aligns with the proposed PBR term. (Exhibit B-1, p. 292)

Commission Determination

The Commission Panel approves the establishment of the 2014–2018 PBR Application Costs deferral account as applied for by FEI and the amortization of this deferral account over the approved PBR period, which is six years, commencing January 1, 2014. The Panel considers this treatment to be consistent with past deferral accounts approved for application-related costs.

TESDA Overhead Allocation Variance Deferral Account

FEI proposes to establish the TESDA Overhead Allocation Variance deferral account to capture the difference between the currently forecasted amount of overheads recovered by FEI from thermal energy customers and any changes to the allocation that may result from the TESDA Report and the TCoC/TPP review requested by the AES Inquiry which is currently under review by the Commission. FEI states that it will address the disposition of any amounts recorded in this deferral account in its first Annual Review. (Exhibit B-1, p. 292)

Commission Determination

The Commission Panel approves the establishment of the TESDA Overhead Allocation Variance deferral account. The Panel directs that the ending balance at December 31 each year be amortized over the following year. The Panel recommends that the carrying costs for this account be determined in a separate Commission process.

The Panel recognizes that there is an application before the Commission to transfer the TESDA deferral account to FAES. In the event that this application is approved, there will no longer be a deferral account in FEI in which the TES related overhead charge can be accumulated. **In this circumstance, the Panel directs that the overhead allocation, along with any other TES related amounts that would otherwise be recorded in the TESDA, be recovered directly from FAES.**

3.3.2 Setting of or Modification to Amortization Period

FEI requests approval to either establish or modify the amortization period for the following deferral accounts:

(i) Midstream Cost Reconciliation Account (MCRA)
(ii) Revenue Stabilization Adjustment Mechanism (RSAM)
(iii) Interest on MCRA and RSAM

(iv) Pension and OPEB Variance deferral account

(v) Customer Service Variance deferral account; and

(vi) Depreciation Variance deferral account.

MCRA, RSAM, and Interest on MCRA and RSAM Deferral Accounts

FEI requests approval to change the amortization period from three years to two years commencing January 1, 2014 for the MCRA and RSAM, as well as the MCRA and RSAM Interest deferral accounts. The reason for this requested decrease in amortization period to two years is because US GAAP requires that "alternative revenue programs" be amortized within 24 months. "US GAAP defines an alternative revenue program as a program that adjusts 'billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts.'" (Exhibit B-1, p. 293)

FEI states that in order to comply with the US GAAP requirements, when midstream rates are reset for the upcoming calendar year, the new rates will be designed to amortize one-half of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates. With regards to the RSAM, the account balance will be recovered from or returned to customers through Delivery Rate Rider 5 over a two year period. (Exhibit B-1, p. 293)

FEI also submits that the amortization period for MCRA interest and RSAM interest should change from three years to two years to align with the requested change to the MCRA and RSAM accounts. (Exhibit B-1, p. 294)

Southern Crossing Pipeline (SCP) Mitigation Revenues Variance Deferral Account

The SCP Mitigation Revenues Variance deferral account captures variances between forecast and actual SCP revenues received each year. Similar to the RSAM and MCRA, FEI has classified this deferral account as "Margin Related" and it currently has an amortization period of three years. (Exhibit B-1-1, Appendix F4, p. 1)

FEI stated that it has not requested to change the amortization for the SCP Mitigation Revenues Variance deferral account from three years to two years because unlike the MCRA and RSAM, this deferral account is not directly subject to the US GAAP revenue recognition requirement. However, FEI also stated that if the Commission were to determine that a two year amortization period was more appropriate in order to align this deferral account with the other margin-related deferral accounts, FEI "is not opposed to making this change." (Exhibit B-11, BCUC 1.189.1)

Commission Determination

The Commission Panel approves FEI's request to change the amortization period from three years to two years for the MCRA and RSAM deferral accounts as well as for the MCRA and RSAM Interest deferral accounts. This reduction in amortization periods is necessary in order for FEI to comply with US GAAP requirements.

The Commission Panel also directs FEI to reduce the amortization period for the SCP Mitigation Revenues Variance deferral account from the currently approved three years to two years so as to create alignment with the other margin-related deferral accounts.

<u>Pension and OPEB Variance Deferral Account</u>

FEI requests approval to extend the amortization period of the Pension and OPEB Variance deferral account from the currently approved three year period to the Expected Average Remaining Service Life (EARSL) of the benefit plans. FEI submits that the EARSL amortization period is more appropriate because it allocates costs over the future period to which they are applicable. FEI has calculated the EARSL for 2014 to be twelve years. FEI states that the 12-year amortization period will be used for the term of the PBR and may be adjusted in the next revenue requirement application based on the calculation of EARSL at that time. (Exhibit B-1, p. 294)

FEI submitted that the nature of the Pension and OPEB costs is uncontrollable and large fluctuations in this deferral account can occur from year to year. Thus, a benefit of the longer amortization period is that it creates smoother rates. However, FEI also pointed out that a shorter amortization period has the benefit of recovering costs from customers sooner rather than later. (Exhibit B-11, BCUC 1.173.1)

When asked what changes in circumstances have led FEI to request an increase in the amortization period, FEI stated that since it filed its 2012–2013 RRA, there has been a large increase in the pension expense which has resulted in a "material variance" in the Pension and OPEB Variance deferral account. FEI attributed the large variance to lower interest rates in 2011 through 2013, which has resulted in a higher pension expense than forecast. The effect of the low interest rates is that they lower the discounting of the liability which results in higher expenses each year. (Exhibit B-11, BCUC 1.173.2.1)

The currently approved 3-year amortization period causes an increase to the 2014 delivery rate of 1.13 percent which equates to an additional $7.1 million in revenue requirement. In comparison, changing the amortization period to 12 years reduces the 2014 delivery rate impact to 0.63 percent. (Exhibit B-24, BCUC 2.333.1)

Commission Determination

The Commission Panel denies FEI's request to change the Pension & OPEB Variance deferral account amortization period from three years to the EARSL. The Panel directs FEI to continue amortizing this deferral account over three years. While the Panel recognizes that significant variances have been experienced in recent years due to low interest rates, the Panel is not convinced that deferring these costs so far into the future is appropriate or beneficial to rate-payers, particularly when taking into account the increased cost to rate-payers caused by the larger accrual of financing which would result if the deferral account balance was amortized over the longer time period.

Customer Service Variance Deferral Account

FEI seeks approval to amortize the 2013 ending credit balance in the Customer Service Variance deferral account over five years commencing January 1, 2014. This deferral account was approved in the 2012–2013 FEU RRA Decision to capture variances between forecast and actual costs resulting from the implementation of the new customer service delivery module. (Exhibit B-1, pp. 294–295)

FEI submitted that "it is important to smooth the rate impacts over the term of the PBR in order to prevent unnecessary fluctuations in rates and provide rate stability for customers." FEI also submitted that a five-year amortization is appropriate because it creates alignment with the existing 2010/2011 Customer Service O&M and Cost of Service deferral account, which is currently being amortized over eight years from 2012 to 2019. (Exhibit B-11, BCUC 1.174.1)

Table 3.14 shows the impact on delivery rates if the Customer Service Variance deferral account is amortized over various time periods:

Table 3.14 FEI Cumulative Delivery Rate Impact

FEI Cumulative Delivery Rate Impact	2014	2015	2016	2017	2018
5 year amortization	-0.72%	-0.68%	-0.64%	-0.60%	-0.56%
3 year amortization	-1.09%	-1.02%	-0.95%	0.00%	0.00%
2 year amortization	-1.54%	-1.44%	0.00%	0.00%	0.00%
1 year amortization	-2.90%	0.00%	0.00%	0.00%	0.00%

(Source: Exhibit B-11, BCUC 1.174.3)

Commission Determination

The Commission Panel approves the requested five-year amortization period for the Customer Service Variance deferral account. The amortization of this deferral account shall commence

January 1, 2014. The Panel agrees that a five-year amortization period is appropriate as it serves to smooth the rate impact over the term of the PBR.

Depreciation Variance Deferral Account

Please refer to Accounting Policy Changes Section 3.2.7 of the Decision for a discussion of this deferral account.

In accordance with the directives in Section 3.2.7 of the Decision, the Panel approves the amortization of the balance in the Depreciation Variance deferral account over one year commencing January 1, 2014. Subsequent to 2014, the Depreciation Variance deferral account shall be discontinued.

3.3.3 Other Deferral Account Requests

FEI requests various other approvals related to the following deferral accounts:

(i) Energy Efficiency and Conservation (EEC);
(ii) Biomethane Program Costs;
(iii) Generic Cost of Capital Application Costs (GCOC);
(iv) Amalgamation and Rate Design Application Costs;
(v) Residual Delivery Rate Riders; and
(vi) On-Bill Financing Pilot Program.

EEC Deferral Account

FEI seeks approval to transfer the balance in the non-rate base EEC deferral account as at December 31, 2013 to the rate base EEC deferral account on January 1, 2014. Additionally, FEI seeks approval to transfer any new amounts accumulated in the EEC deferral account during the PBR period to the rate base EEC deferral account in the following year. FEI proposes to amortize the amounts in the rate base EEC deferral account over 10 years commencing in 2014. (Exhibit B-1, pp. 295–296)

Please see the "Demand-Side Management and Energy Efficiency and Conservation" Section 4.6.2 of the Decision for further discussion and determinations on these requests.

Biomethane Program Costs Deferral Account

The Biomethane Program Costs deferral account was approved pursuant to Order G-194-10 to capture the biomethane costs applicable to all customers incurred prior to January 1, 2012 and to amortize these deferred costs over three years commencing January 1, 2012. (Exhibit B-1-1, Appendix F4, p. 2)

FEI is requesting approval to capture the application costs related to the FEI 2012 Biomethane Application filed with the Commission December 19, 2012 in this existing deferral account. FEI projects the total balance related to these costs to be approximately $135,000. FEI proposes to amortize these new additions to the deferral account over a one year period in 2014. (Exhibit B-1, p. 296)

Commission Determination

The Panel denies FEI's request to capture these application costs in the existing Biomethane Program Costs deferral account. In the 2013 Biomethane Decision, the Commission directed "all interconnection and Biomethane Program Costs are to be recorded in the BVA along with the cost of supply." (2013 Biomethane Decision, p. 65) Recording these costs in the BVA provides FEI with the opportunity to recover all of the Biomethane Program costs from biomethane customers and the Panel expects it will make every effort to do so. **Accordingly, FEI is instead directed to record these costs in the Biomethane Variance Account.**

GCOC Application Costs Deferral Account

FEI seeks approval for a rate base deferral account to record the forecast costs related to the GCOC Stage 1 proceeding, less the amounts recovered from other affected utilities. The balance in this deferral account will be allocated to FEVI, FEW and Fort Nelson customers based on the Commission's levy calculation and the utilities' share of the previous year's total sales converted to gigajoules. FEI proposes to amortize the balance in this deferral account over two years beginning in 2014. (Exhibit B-1, p. 297)

Commission Determination

The Commission Panel approves the establishment of a rate base deferral account for the GCOC Stage 1 Application Costs. The Panel also approves the amortization of the balance of this account over two years beginning January 1, 2014. This treatment is consistent with past approvals for deferral accounts of a similar nature.

Amalgamation and Rate Design Application Costs Deferral Account

As part of FEU Common Rates, Amalgamation and Rate Design Application, FEU were approved to establish a non-rate base deferral account, attracting AFUDC, within FEI to capture application-related costs. FEI forecasts the ending 2013 balance in this deferral account, including AFUDC, to be $1.7 million. FEI requests approval to transfer its portion of these costs, as well as its portion of the costs incurred for the Reconsideration Application that was filed on April 26, 2013, and approved on February 26, 2014, pursuant to Order G-26-14, to rate base beginning January 1, 2014. FEI proposes to amortize the balance in this deferral account over three years beginning in 2014. The remaining portion of the costs not transferred to FEI's rate base will be allocated amongst FEU on the basis of average customers. (Exhibit B-1, pp. 297–298)

FEI submitted that it chose a three-year amortization period to balance the need to smooth rates due to the fairly high costs associated with the amalgamation and reconsideration proceedings while mitigating the negative impact to amalgamated customers of a longer amortization period. (Exhibit B-11, BCUC 1.176.4)

Commission Determination

The Commission Panel approves the transfer of FEI's portion of the balance of the Amalgamation and Rate Design Application Costs, including the Reconsideration costs, which are currently being held in a non-rate base deferral account, to rate base beginning January 1, 2014. The Panel also approves the amortization of the balance of this rate base deferral account over three years commencing January 1, 2014. This treatment is consistent with past approvals. Further, a three-year amortization period appropriately balances rate smoothing and inter-generational equity.

Residual Delivery Rate Riders Deferral Account

As part of the 2012–2013 FEU RRA Decision, FEI received approval to combine three residual non-rate base deferral account balances into one account, the Residual Delivery Rate Riders deferral account, and to recover the balance through delivery rates in 2012.

FEI now seeks approval to combine three more residual deferral accounts into this deferral account: the Commodity Unbundling non-rate base deferral account (Rate Rider 8); the Earnings Sharing/Capital Incentive Mechanism rate base deferral account (Rate Rider 3); and the Delivery Rate Refund Rider non-rate base deferral account (Rate Rider 4). FEI forecasts a combined credit balance of $38,000 from these accounts at the end of 2013 and proposes to amortize this balance over one year in 2014. Table 3.15 shows the breakdown of the three Rate Rider balances.

Table 3.15 Breakdown of Rate Rider Balances

Commodity Unbundling - Rate Rider 8		($93,022)
Earnings Sharing/Capital Incentive Mechanism - Rate Rider 3		84,383
Delivery Rate Refund Rider - Rate Rider 4		(29,383)
Total	$	(38,022)

(Source: Exhibit B-11, BCUC 1.177.1)

FEI states that due to the change to the 2013 ROE and equity structure as approved by Order G-75-13, it will capture the amount to be returned to customers and the offsetting rider refunds to customers in the Delivery Rate Refund Rider non-rate base deferral account (Rate Rider 4). This may create an additional balance remaining in the non-rate base deferral account in 2014. Thus, FEI is seeking approval to transfer any potential balance remaining in this account in 2014 to the Residual Delivery Rate Riders deferral account for recovery over a one year period in 2015. (Exhibit B-1, p. 298)

Commission Determination

The Commission Panel grants approval to FEI to combine the residual balances in Rate Riders 3, 4 and 8 into the Residual Delivery Rate Riders Deferral Account and to amortize the balance into rates in 2014. **The Panel also approves the transfer any remaining balance in Rate Rider 4 which exists in 2014 to the Residual Delivery Rate Riders Deferral Account for amortization into rates in 2015**. The consolidation of these deferral accounts is consistent with the treatment approved in the 2012–2013 FEU RRA Decision and assists in streamlining the management of these deferral accounts.

<u>On-Bill Financing Pilot Program Deferral Account</u>

FEI requests approval to transfer the ending 2014 balance in the On-Bill Financing (OBF) Pilot Program non-rate base deferral account to rate base on January 1, 2015. FEI also requests approval to continue to recover the balance from the OBF pilot program customers over approximately a ten-year period until the account is fully recovered. (Exhibit B-1, p. 299)

Pursuant to Commission Order G-163-12, approval was granted to FEI to establish the non-rate base OBF Financing Deferral Account attracting AFUDC to capture, on a net-of-tax basis, the principal loan balance provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries. (Order G-163-12, Directive 4)

FEI submits that in its OBF Pilot Program Application it requested approval to transfer the non-rate base deferral balance to rate base effective January 1, 2015, and include the balance as part of its revenue requirements application, starting in 2015. However, this part of FEI's request was not addressed in Order G-163-12, so FEI is now requesting this approval in the current Application. (Exhibit B-11, BCUC 1.178.1)

FEI anticipates that there will be a balance of $541,000 at the end of 2014 (Exhibit B-11, BCUC 1.178.2).

Commission Determination

The Panel approves FEI's request to transfer the ending 2014 balance in the non-rate base OBF Pilot Program deferral account to rate base on January 1, 2015. The Panel directs the balance to be recovered from OBF pilot program customers over a 10-year amortization period or until the balance has been fully recovered. This treatment is consistent with other Energy Efficiency and Conservation related deferrals.

3.3.4 Discontinuance of Deferral Accounts

Table 3.16 outlines the requests made by FEI related to discontinuing of various deferral accounts:

Table 3.16 FEI's Proposed Discontinued Deferral Accounts

Type Of Change	Account	Projected 2013 Ending Balance	Request and Reference
Discontinuance	Southern Crossing Pipeline Tax Reassessment	$(32,000)	Amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015. (Exhibit B-1, Section D4, p. 305; Exhibit B-1-5, Appendix G2, Schedule 48)
	Tilbury Property Purchase (Subdividable Land)	$(220,000)	Amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016. (Exhibit B-1, Section D4, p. 305; Exhibit B-1-5, Appendix G2, Schedule 48)
	Fuelling Stations Variance Account	$159,000	3 year amortization period commencing January 1, 2014 with discontinuation of this account effective January 1, 2017. (Exhibit B-1-1, Appendix H, pp. 15-16; Exhibit B-1-5, Appendix G2, Schedule 48)
	Overhead and Marketing Recoveries from NGT Class of Service	$(70,000)	1-year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016. (Exhibit B-1, Section D4, p. 306; Exhibit B-1-5, Appendix G2, Schedule 48)
	RS 16 Application Costs	$130,000	1-year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016. (Exhibit B-1-3, Section D4, p. 307; Exhibit B-1-5, Appendix G2, Schedule 48)
	RS 16 Costs and Recoveries	$(20,000)	1-year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016. (Exhibit B-1-3, Section D4, p. 307; Exhibit B-1-5, Appendix G2, Schedule 47)
	NGV for Transportation Application	$36,000	Discontinuation of this account effective January 1, 2016. (Exhibit B-1-3, Section D4, p. 307; Exhibit B-1-5, Appendix G2, Schedule 48)
	2011 CNG and LNG Service Costs and Recoveries	$(34,000)	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	Olympic Security Costs	-	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	IFRS Implementation Costs	-	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	2009 ROE and Cost of Capital Application	$328,000	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	2010-2011 Revenue Requirement Application	-	Discontinuation of this account effective January 1, 2015. (Exhibit B-15, Section E, Schedule 50)
	2012-2013 Revenue Requirement Application	$205,000	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	CCE CPCN Application	$94,000	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	Deferred Removal Costs	$(131,000)	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	US GAAP Conversion Costs	$(853,000)	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	US GAAP Transitional Costs	$1,425,000	Discontinuation of this account effective January 1, 2015. (Exhibit B-1-5, Appendix G2, Schedule 48)
	Mark to Market - Customer Care Enhancement Project	-	Discontinuation of this account effective January 1, 2014. (Exhibit B-1, Section D4, p. 307)

Based on the balances provided in FEI's February 21, 2014 Evidentiary Update and as displayed in the above table, the total forecasted balance at the end of 2013 for the deferral accounts requested to be discontinued is approximately $1.017 million.

No Interveners commented on FEI's request to discontinue these deferral accounts.

Commission Determination

The Commission Panel finds that unused deferral accounts should be discontinued and approves FEI's request to discontinue the deferral accounts listed in Table 3.16 above as outlined in the Application and in subsequent Evidentiary Updates.

3.4 Issues Related to the 2012–2013 FEU RRA Decision

3.4.1 Asset Losses

In the 2010-2011 TGI RRA, TGI proposed to adopt IFRS for both financial and regulatory reporting purposes. At that time, there was uncertainty around whether IFRS would permit gains and losses on disposal of assets to be charged to accumulated depreciation instead of being immediately taken into income. The TGI 2010–2011 Negotiated Settlement Agreement (2010–2011 NSA) approved TGI's proposal to record gains and losses on disposition or retirement of property, plant and equipment in 2010 and 2011 in a deferral account (Gains and Losses deferral account) for disposition as part of the TGI's next revenue requirements application.

In 2011, TGI decided to adopt US GAAP instead of IFRS. On February 9, 2011 FEU filed an application requesting Commission approval to adopt US GAAP. On July 7, 2011, Commission Order G-117-11 approved FEU to adopt US GAAP for the period January 1, 2012 to December 31, 2014. On July 19, 2011, FEU updated its 2012-2013 RRA to reflect the adoption of US GAAP. The update did not include did not include the discontinuation of the Gains and Losses deferral account.

The Gains and Losses deferral account has increased from $14.8 million in 2010 to a forecast balance of $32.250 million in 2013. FEI stated that only 5 percent of the opening balance is being amortized each year. (Exhibit B-24, BCUC 2.323.1; Exhibit B-1-5, Attachment 4, Section E, Schedule 50)

Table 3.17 Gain/Losses on Disposition Deferral Account for 2010-2013 (000's)*

Year	Opening Balance	Changes during years	Closing Balance
2010	-	14,817	14,817
2011	14,817	6,182	20,999
2012	20,999	6,091	27,090
2013	27,090	5,160	32,250

**Positive numbers represent Losses.*

(Source: Exhibit B-24, BCUC 2.323.1)

In the 2012-2013 FEU RRA, the Commission noted that the "[f]ailure to prudently maintain and/or use assets appropriately could affect… assets' useful lives" and that there will be "asset losses upon retirement that will likely not be recoverable from ratepayers." The Commission also stated that "these considerations are especially important during a PBR period" and that changes in maintenance and repair cost minimization could have a deleterious impact on the service life of an asset. (2012–2013 FEU RRA Decision, p. 87)

FEI noted that the growth in the Gains and Losses deferral account balance is expected to continue to grow. FEI reiterates that these losses should be considered normal and that retirement losses and gains are expected to net out to zero over the life of the assets. The Company stated that the concerns from the 2004 Plan regarding the accumulation of asset losses due to depreciation rates being lower than the asset lives will be addressed by FEI providing an updated depreciation study and annually updating its estimate of asset losses throughout the PBR Period. FEI also stated that the "earliest FEI expects to provide an updated depreciation report is in 2015". (Exhibit B-1, pp. 267, 273–274; Exhibit B-24, BCUC 2.323.1, 2.323.5)

Commission Determination

The Commission Panel notes that the need for this deferral account was predicated on FEI adopting IFRS. Given that FEI has adopted US GAAP instead of IFRS, the need for this deferral account no longer exists**. Accordingly, the Panel directs FEI to discontinue use of the Gains and Losses deferral account, effective January 1, 2014**. In addition, the Panel does not agree that 20 years is an appropriate amortization period for this account. The Commission Panel finds 10 years to be the appropriate balance between the need for rate smoothing with the need to and minimize inter-generational inequity. **Therefore, the Panel directs FEI to amortize the December 31, 2013 balance in the Gains and Losses deferral account over 10 years beginning January 1, 2014.**

3.4.2 Uniform System of Accounts

In the 2008 RRA Decision,[16] the Commission approved the FEI request to diverge from the Commission's GAS Uniform System of Accounts (USoA) for reporting its O&M in Accounts 600 to 999 and to prepare reports using the New Code of Accounts, providing both a resource-based view and an activity-view. The Commission also noted that the New Code of Accounts is to provide consistent and informative reporting similar to the Commission's Uniform System of Accounts for Gas Utilities. (2008 RRA Decision, p. 4)

Directive 63 of the 2012–2013 FEU RRA Decision directed FEU to investigate the cost of fully converting to the USoA and develop a plan to allow FEU to fully adopt the USoA prior to filing their next RRA (2012–2013 FEU RRA Decision, Appendix A, p. 11). FEU submitted a compliance filing on October 12, 2012 (USoA Compliance Filing) that included a report on the USoA with proposals to address the underlying concerns of the Directive 63 of Order G-44-12. (Exhibit A2-13) On

16 In the Matter of An Application by Terasen Gas Inc. for Approval of 2008 Revenue Requirements and Delivery Rates; Decision and Order G-153-07 dated December 10, 2007 (2008 RRA Decision).

December 3, 2012 the Commission issued a letter that accepted FEU's proposed alternate approach for next RRA only. The letter also stated that in "the next RRA the Commission will assess whether FEU is required to either comply with Directive 63, continue with the alternate approach for further RRA's, or implement some other approach as the Commission finds appropriate at that time." (December 3, 2012 the Commission letter)

Issues regarding FEU's ability to provide information at a sufficient level of detail for the Commission to fully analyze the information provided were discussed in 2012–2013 FEU RRA, IRs on the USoA Compliance Filing and the current proceeding. (2012-2013 FEU RRA Decision, p. 141, A2-15)

In response to IRs on the USoA Compliance Filing, FEU stated that its unable to track customer education costs Employee Expenses, Fees and Administration Costs (this includes advertising costs), and Legal Fees and Retainers throughout FEU. Furthermore, FEU stated that "If there is a requirement to know the total costs (O&M and capital) at this level of detail, it can be provided in information requests". (Exhibit A2-15, BCUC 6.0, 8.0) In the current proceeding, FEI was unable to provide five-year comparable information in BCUC 1.81.2, 1.101.1, 1.110.1, 1.127.3, 1, 1.129.1, 1.137.2 1.138.2, and other IRs (Exhibit B-11). In addition, states it was unable to provide comparable 2010-2013 O&M due to a "different set of accounting classifications between O&M and capital", changes in set of circumstances and organizational changes (Exhibit B-8, CEC 1.60.1).

At the September 5, 2013 Procedural Conference the CEC stated that "[if] the application satisfied the needs of Staff and interveners, there probably wouldn't have been as many IRs" and that the "application is not as comprehensive as expected, and that the analysis and empirical evidence needs to be improved" (T1:60).

FEI submits that the New Code of Accounts provides more meaningful and comparable information than the USoA and is preferable to adopting the USoA (FEI Non PBR Final Argument, p. 65). FEI stated that there is more value to the adoption of a common USoA in Alberta than in BC because of the number of utilities in Alberta, the Alberta Utilities Commission requirement for "consistency of accounting and other policies by the utilities." FEI contrasts Alberta's five major electric utilities to "only two major electric utilities in BC. Each utility manages its O&M differently in BC, and the adoption of the BCUC USoA is unlikely to improve the ability to compare financial information across utilities, which was one of the main benefits in the [AUC]'s case." Further, FEI stated that customer representatives were willing to pay the costs in Alberta, and given that "no customer groups have taken issue with FEU's current reporting, FEU do not believe this has been established to be true in BC" (Exhibit B-24, BCUC 2.308.5.2). The Company also noted that there was a lack of interest from interveners and that "there were no intervener submissions on the topic of the BCUC Uniform System of Accounts". (FEI Non PBR Reply, p. 67)

Commission Determination

The Panel confirms the Commission's statement on page 141 of the 2012–2013 FEU RRA Decision that it is not appropriate to relieve FEU "of the responsibility to report 'granular' account level details of their O&M accounts on a comparable basis because it restricts the ability of the Commission to fully analyze the information provided." The Commission Panel finds this particularly relevant given the proposed PBR and the directive for FEI to conduct a bench marking study.

The Panel considers that the use of the USoA for reporting purposes provides consistent and comparable information at an account level over time. The Panel also notes that if forecasting in future RRAs followed this same system of accounts, the comparison of forecast to actual results at the account level would be more transparent, reduce the number of IRs and increase efficiency. FEU's adoption of the USoA may also assist the bench marking study by increasing the comparability of FEU's reporting with other jurisdictions that use the USoA. Given these advantages, the Commission Panel believes there are substantial benefits to be derived from FEU fully adopting the USoA. **Therefore, the Commission Panel directs FEU to fully adopt the USoA and commence tracking all costs under the USoA as of the beginning of 2016. The Panel further**

directs FEI to file, for approval, by no later than March 31, 2015, a plan describing how it will implement this change.

3.5 Other Reporting Issues

During the review of the Application, Commission staff identified two issues regarding the presentation of financial information:

1. Non-rate base deferral accounts are not included in the financial schedules
2. Gas plant excluded from rate base (i.e. main extensions with no customer attachments) are not shown in the financial schedules

(Exhibit B-1, Section E, Financial Schedules – 2014 Delivery Rates; Exhibit B-1-1, Appendix F5, Non Rate Base Deferrals)

There were no Intervener or FEI submissions on this issue.

Commission Determination

The Commission Panel is of the view that all non-rate base deferral accounts and gas plant excluded from rate base should be included in FEI's financial schedules. The Panel considers that including these items in FEI's financial schedules will increase transparency and provide a more fulsome view of FEI's activities. Therefore, **the Commission Panel directs FEI to include non-rate base deferral accounts and gas plant excluded from rate base in its financial schedules for the first Annual Review.**

4.0 DEMAND-SIDE MANAGEMENT / ENERGY EFFICIENCY AND CONSERVATION

4.1 Introduction and Approvals Requested

FEU request, under section 44.2 of the UCA, acceptance of EEC expenditure schedules for 2014 to 2018. These EEC expenditures are not subject to the PBR formula. Instead they are captured in deferral accounts and amortized as approved by the Commission. FEU submit that the 2014-2018 EEC expenditure schedule is an extension of its previously accepted 2012–2013 EEC plan. (FEI Non PBR Final Argument, pp. 75–76)

FEU submit that the current five-year 2014-2018 EEC Plan marks a milestone in FEU's EEC portfolio as it transitions from relatively rapid expansion to a more stable and sustained delivery of existing programs. By way of background, FEU were approved to spend $36.2 million in 2013, which is more than three times FEU's actual EEC spend of $10 million in 2010. (FEI Non PBR Final Argument, p. 75; FEU 2012–2013 RRA Decision, pp. 152, 169)

The proposed 2014-2018 EEC expenditure schedule is shown in Table 4.1. It comprises EEC programs in the residential, commercial and industrial sectors, as well as funding for Conservation, Education and Outreach (CEO), Innovative Technologies, and Enabling Activities. FEU requests approval for five new EEC programs and also requests approval for regulatory accounting treatment of EEC expenditures, and endorsement of recognition of spillover effects and attribution of savings from codes and standards. (Exhibit B-1-1, Appendix I, pp. 26–28, 31)

Table 4.1 FEU's Proposed 2014-2018 EEC Expenditure Schedule

	Actual Expenditures ($000s)	Approved Expenditures ($000s)	Requested Expenditures ($000s)				
Program Area	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	11,295	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	603	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	4,865	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	358	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	394	1,502	1,207	1,218	1,233	1,218	1,210
CEO	2,200	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities	4045*	n/a	4,515	5,015	4,420	4,425	4,365
Totals	19,715	35,574	34,353	36,537	35,839	35,388	35,874

* The value for Enabling Activities for 2012 is in fact for Portfolio-level activity

(Exhibit B-1-1, Appendix I, p. 17)

Table 4.2 shows the distribution of EEC spending by customer class. FEU submit that they are proposing a fairly even distribution of EEC spending as a percentage of customer class revenues:

Table 4.2 FEU EEC Spending by Customer Class

	2012	**2014**
Residential	2.2%	2.4%
Commercial	1.3%	3.2%
Industrial	0.4%	2.5%

(Source: Exhibit B-24, BCUC 2.369.6)

FEU state that EEC spending as a percentage of revenue was weighted higher towards residential customers in 2012 as EEC residential programs for the most part are more mature than those in the commercial and industrial areas. As FEU enter into the PBR period, they project that commercial and industrial EEC expenditures will experience increases compared to 2012. (FEI Final Argument Non PBR Issues, pp. 89–90)

FEU state that programs are available to all customers across all service territories, and that actual EEC incentives that can be allocated to a particular utility will be allocated on an as-incurred basis, with non-incentive expenditure allocated as per the previously-approved split based on an average customer count, which is approximately 89 percent to Mainland, 10 percent Vancouver Island and 1 percent to Whistler. (FEI Final Argument Non PBR Issues, p. 93)

BCSEA considers FEU's allocation of EEC spending among customer classes to be acceptable. BCSEA supports FEU efforts to accelerate the update of industrial programs through broadening the funding opportunities and increased collaboration with FortisBC and BC Hydro. (BCSEA Final Argument, pp. 49-50)

In the following sections the Commission Panel will first examine and provide direction regarding how the EEC spending request will be evaluated (EEC Cost Effectiveness Framework). We will then examine EEC programs and funds requested and provide direction as to the funding amounts which are to be accepted for the 2014-2018 test period. Finally, the Commission Panel will discuss specific issues that have arisen in this Proceeding: movement of funds among categories; amortization period; evaluation, measurement and verification (EM&V) approach and EEC fund administration – TES projects.

4.2 Regulatory Framework

Pursuant to section 44.2(3) of the UCA, the Commission must accept FEU's EEC expenditure schedule if the Commission considers that the expenditures are in the public interest. Subsection 44.2(4) allows the Commission to accept or reject a part of a schedule.

Section 44.2(5) of the UCA, requires the Commission, in making its determinations, to consider:

- the applicable of British Columbia's energy objectives;
- the most recent long-term resource plan filed by FEU under section 44.1 of the UCA;

- the extent to which the expenditure schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act;*
- the interests of persons in British Columbia who receive or may receive service from FEU; and
- if the schedule includes expenditures on demand side measures, whether those demand-side management measures proposed are cost-effective within the meaning prescribed by regulation, if any. [Demand-Side Measures Regulation BC Reg 326/2008 as amended by BC Reg 228/2011 and BC Reg 141/2014 is applicable]

Clean Energy Act

The Commission is required to consider British Columbia's energy objectives as laid out under the *Clean Energy Act* (CEA) in reviewing any proposed expenditure schedule. The objectives are laid out in section 2 of the CEA and relate in large measure to the use of clean energy or renewable resources, promotion of energy conservation and efficiency and the reduction of greenhouse gas emissions.

BC Energy Objectives

The applicable British Columbia energy objectives relating to EEC include the following objectives referred to in section 2 of the *Clean Energy Act:*

b) to take demand-side measures and to conserve energy …

d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources,

g) to reduce BC greenhouse gas emissions.

Other CEA objectives which may be relevant to EEC expenditures FEU propose are:

h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia,

j) to encourage communities to reduce greenhouse gas emissions and use energy efficiently,

k) to encourage economic development and the creation and retention of jobs.

The BC Energy Plan also supports utilities in BC pursuing all cost effective and competitive demand-side management programs.

Long-Term Resource Plan

FEU's most recently accepted Long Term Resource Plan (LTRP) was filed in 2010. An updated LTRP was submitted to the Commission in March 2014 and is currently under review. In accepting the 2010 FEU LTRP, the Commission stated "… the 2010 LTRP, while accepted, is viewed as being just adequate." The Commission previously directed that future LTRP's include a more detailed presentation of future EEC programs over a longer timer period and funding scenario analysis.[17]

Given the lack of EEC detail in the 2010 LTRP and that there is now a new (2014) LTRP that is currently under review, the Panel have not placed significant weight on ensuring consistency with the 2010 LTRP in this Application.

Demand-Side Measures Regulation

The Demand Side Measures Regulation (DSM Regulation) defines a utility's "plan portfolio" as the class of demand-side measures that is composed of all of the demand-side measures proposed by a public utility in a plan submitted under section 44.1 of the UCA. Section 3 of the DSM Regulation sets out all the criteria that must be met for a utility's plan portfolio to be deemed 'adequate' for the purposes of subsection 44.1(8)(c) of the UCA. To meet these criteria the plan portfolio must include:

(a) A demand-side measure intended specifically

[17] In the Matter of the Terasen Utilities 2010 LTRP Decision, pp. 23–24.

(i) To assist residents of low-income households to reduce their energy consumption, or

(ii) To reduce energy consumption in housing owned and operated by

(A) A housing provider incorporated under the *Society Act* or the *Cooperative Association Act*, or

(B) A band within the meaning of the *Indian Act* (Canada),

if the benefits of the reduction primarily accrue to

(C) The low-income households occupying the housing,

(D) A housing provider referred to in clause (A), or

(E) A band referred to in clause (B) if the households in the band's housing are primarily low-income households.

(b) A demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

(c) An education program for students enrolled in schools within the public utility's service area;

(d) An education program for students enrolled in post-secondary institutions in the utility's service area.

The DSM Regulation describes the cost-effectiveness tests to be used by the Commission in evaluating the EEC proposal. Ministerial Order 233, dated June 4, 2014, amended the DSM Regulation (BC Reg. 326/2008) in a number of areas, including an expanded definition of 'low income household' and changing the calculation of FEU's cost of energy for the modified Total Resource Test (mTRC). FEU submit that these changes do not result in an expansion of their EEC funding request. (T8:1389)

Section 4 of the DSM Regulation provides for the calculation of the effectiveness of demand-side measures. It also prescribes how the "cost-effectiveness" of a demand-side measure is to be determined for demand-side measures proposed in an expenditure portfolio. The prescribed calculation is called the modified TRC (mTRC) to distinguish it from the more traditional Total Resource Cost (TRC) test.

Section 4(1.1)(c) of the DSM Regulation states that the Commission must, when making determinations of cost effectiveness by applying the total resource cost test for any proposed demand-side measure filed pursuant to section 44.2 of the UCA which is not directed at residents in low income households:

i. increase the benefits of the demand-side measure by an amount that does not exceed an amount proposed by the public utility for this purpose, if the commission is satisfied that the amount represents the participant or utility non-energy benefits of the demand-side measure;

ii. if the benefits of a demand-side measure have not been increased under subparagraph (i) or if the benefits of the expenditure portfolio of which the demand-side measure is a part has not been increased by 15% or more as a result of an increase under subparagraph (i), increase the benefit of the demand-side measure by an amount that

    (A) increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part, and

    (B) is equal to the increase made under this subparagraph for all the other demand-side measures that are part of the expenditure portfolio.

The DSM Regulation generally requires that FEU EEC measures (or the portfolio as a whole) are cost effective from a BC perspective (i.e. they provide a net benefit to BC). In addition, at least 67 percent of the proposed EEC spending (with some exemptions) has to be cost effective from a BC perspective without including any broader BC benefits related to emission reduction and non-energy benefits (such as improved comfort or health). (Exhibit B-11, BCUC 1.217.1)

The DSM Regulations do not allow the Commission to reject EEC programs on the basis that incremental sales to the target customer are profitable to the utility. However, an issue for the Commission Panel to consider is to what extent, if any, the overall EEC budget should be reduced as a result of concerns that cost-effective EEC can place upward pressure on rates. (Exhibit B-24, BCUC 2.364.3.2)

4.3 EEC Cost Effectiveness Framework

The Total Resource Cost (TRC) Test measures the benefit to BC excluding emissions and non-energy benefits, while the modified Total Resource Cost (mTRC) Test can include emissions and non-energy benefits. A TRC/mTRC ratio of higher than 1:1 indicates that BC benefits exceed BC costs. Both the TRC and the mTRC are not affected by changes in the level of FEU's EEC incentives provided to customers. This is because the TRC and mTRC effectively measure whether customers are making suboptimal decisions from a BC perspective (for example, by not adequately insulating their home) and not whether it is cost effective for the utility to address any identified inefficiency. (Exhibit B-11, BCUC 1.217.2, 1.217.5)

The Commission has the option to apply either the TRC or the mTRC test to each individual program, or to the portfolio as a whole. The Commission has opted in the past to apply this test on a portfolio basis. This provides FEU with the flexibility to undertake programs that are expected to provide a net BC benefit but where energy savings are hard to measure or where energy savings are low in the short term, provided there are other programs in its portfolio that provide offsetting benefits and/or savings. (Exhibit B-1-1, Appendix I, p. 23)

For up to 33 percent of EEC funding which passes the mTRC but not the TRC,[18] the DSM Regulations also allow the Commission to consider if the proposed programs are cost effective from a utility perspective (i.e. to determine if it is cheaper for the utility to encourage customers to improve their energy use decisions, for example by providing home insulation incentives, compared to supplying the additional energy that would be required in the absence of improved insulation). This test is called the Utility Cost Test (UCT) and compares the cost of the EEC program (incentive and utility administrative costs) to FEU's avoided energy cost. A UCT ratio of higher than 1:1 indicates that utility benefits exceed utility costs. An issue to be addressed in this Decision is to what extent, if

[18] Excluding specified DSM measures, public awareness programs and programs required for adequacy.

any, the Commission should encourage the utility to focus on EEC programs that reduce total utility costs. (Exhibit B-11, BCUC 1.219.2)

A lower total utility cost, however, does not necessarily translate into lower rates. Variable ($/GJ) gas rates tend to be higher than avoided gas costs for residential and commercial customers. This occurs because these costs often also recover some of the sunk costs of the pipes and other infrastructure used to deliver gas to the customer. For example, FEI's variable energy charge for a residential customer in the Lower Mainland is $9.564/GJ, and for a customer in Vancouver Island is $14.325/GJ.[19] However, FEU estimate their long-run avoided cost of gas at $5.064/GJ (Exhibit B-11, BCUC 1.218.2). Lower revenues from gas sales will therefore tend to exceed avoided gas costs, causing upward pressure on rates overall. The test to measure this effect is called the Rate Impact Measure (RIM) test. This is less of an issue for industrial EEC because for firm service industrial customers the majority of the revenue is fixed through monthly demand and basic charges. (Exhibit B-11, BCUC 1.212.1)

The following section will also consider certain inputs used in the cost effectiveness tests, specifically: the avoided cost of gas, spillover effects and attribution of savings from codes and standards.

4.3.1 To what Extent is a low UCT result a concern?

The issue of a low UCT test result was addressed in an Energy Efficiency Screening Coalition 2013 paper titled 'Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the US' which stated:

> "… the Utility Cost test and the Societal Cost test [mTRC] both represent reasonable methods for identifying the cost-effectiveness of energy efficiency resources. Ideally, both tests should be considered when screening energy

[19] Source: FEI and FEVI online tariff pages August, 2014.

> efficiency resources, because they both provide useful information regarding cost effectiveness. … regulators may decide that certain lost opportunity or market transformation efficiency programs whose Utility Cost test benefit-cost ratios are less than one are nonetheless in the public interest because of their unquantified benefits, without specifying proxy adders or alternative benchmarks." (Exhibit C4-13, BCUC 1.2.3.2, Attachment b, pp. 4–6)

FEU submit that, while it is useful to calculate and monitor the UCT at the portfolio and individual program level, only the TRC/mTRC should be used to determine whether a program is implemented or not. BCSEA agrees with FEU's position. (FEI Non PBR Final Argument, p. 101; BCSEA Final Argument, p. 51)

FEU confirm that the size of the customer incentive does not affect the TRC/mTRC result. However, FEU submit that "The appropriate way to set program incentive levels is by using market research and good program design approaches, rather than by applying additional cost effectiveness hurdles …" (FEI Non PBR Final Argument, pp. 101–102)

Regarding the ability of EEC to support BC emission reduction targets, FEU submit that they are committed to supporting Provincial efforts to reduce GHG emissions and that EEC programs will lead to reductions in greenhouse gas emissions of 1,198,677 tonnes carbon dioxide equivalent (tCO2e). However, FEU forecast that carbon dioxide equivalent (CO2e) emissions from FEI's commodity sales subject to the carbon tax will still increase from F2014 to F2018. (Exhibit B-1-1, Appendix I, p. 4, Exhibit B-11, BCUC 1.208.1.1)

Commission Determination

The Panel notes that the DSM regulation states that the commission *may* determine that a demand-side measure, other than

(a) a specified demand-side measure,

(b) a public awareness program,

(c) a demand-side measure referred to in section 3 (a), or

(d) a demand-side measure that is cost effective without applying subsection (1.1) but after applying subsection (1.4)

is not cost effective if the demand-side measure would not be considered cost-effective under the utility cost test. **Accordingly, where appropriate, the Panel may consider the UCT as a checkpoint in evaluating EEC programs requiring the mTRC, along with other considerations including the ability of customers to participate in EEC programs.**

The Commission Panel will not require that programs requiring the mTRC test also pass the UCT, as the Panel recognises that EEC programs which do not pass the UCT could nonetheless be considered appropriate for FEU to undertake because of their unquantified benefits (such as supporting BC emission reduction targets or other objectives of the BC Energy Plan). A low UCT could also result from energy savings that are hard to measure or low in the early years. However, a program with a low UCT could also indicate that an EEC program proposed may not be the most cost effective means of incenting customers to change their investment or consumption behaviours, and other programs could be more effective. For this reason, the Panel considers it appropriate that the result of the UCT test be considered, even if it is not determinative.

In evaluating the reasonableness of allocation of EEC funding between EEC programs that pass the TRC/mTRC, the Commission Panel determines that the UCT result is a relevant consideration. Other relevant considerations include providing broad opportunities for customers to participate, TRC/mTRC cost-effectiveness result, addressing 'lost opportunities' (e.g., new construction) and retaining a level of customer and trades engagement. Specifically, the Panel supports a focus on effectiveness in the management of the EEC portfolio. This includes a number of aspects, including ensuring that the most effective programs are pursued and an appropriate balance pursued in terms of different customers' ability to access EEC programs.

4.3.2 To What Extent is Rate Impact a Concern?

FEU submit that in this proceeding they have taken the Commission's 2012–2013 RRA Decision as representative of the level of EEC expenditures and rate impacts that are appropriate for the programs it is proposing (FEI Non PBR Final Argument, p. 78). By way of background, FEU put forward an EEC funding request of $74.5 million for 2012 and 2013, which was amended to $64.5 million for 2012 and 2013 following the release of the EEC NGV Incentives Decision. In the 2012-2013 RRA Decision, the Commission further reduced the funding request to $29.7 million for 2012 and $36.2 million for 2013 primarily as a result of exclusion, from EEC funding, of load building programs, lack of evidence to justify certain new programs and concerns that FEU are 'trying to move too far too fast.' (2012-2013 FEU RRA Decision, pp. 145, 161–164, 168, 169)

FEI also submits that "[f]rom FEI's perspective, the primary objectives of DSM are to … maintain the competitive position of natural gas relative to other energy sources" (Exhibit B-1-1, Appendix A, p. 3).

BCSEA counter that "the Commission should direct FEU to prioritize the achievement of cost-effective EEC savings over customer rate impacts" (BCSEA Final Argument, p. 8). BCSEA also note that the EEC legislative framework includes the B.C. energy objectives, cost-effectiveness, and other factors of which rate impacts are but one. BCSEA further states that it welcomes FEU's commitment to consult members of the EEC Advisory Group regarding possible re-applications for additional EEC funding. (BCSEA Final Argument, p. 47)

Commission Determination

The Commission Panel determines that rate impacts are relevant when considering the interests of persons in British Columbia who receive or may receive service from FEU. However, the focus of this consideration should be on mitigating rate impacts for non-participants, and not on maintaining the competitive position of natural gas. The Panel considers that reducing the level of cost-effective EEC in order to maintain the competitive position of gas may be contrary to BC energy objectives, specifically objectives in support of emission reductions.

The Commission Panel finds it appropriate to assess rate impact considerations only at the portfolio level, and not at the individual program level. Similar to consideration of UCT results, rate impact considerations are not a hard and fast rule. BC Energy Plan objectives require utilities to pursue all cost effective EEC, and whether opportunities are available to ensure all customers, in particular 'hard to reach' customers such as low-income customers and renters, can participate in EEC programs.

The Commission Panel also determines that FEU should not use the Commission's FEU 2012–2013 EEC approval as a guide to the upper level of rate impacts that are appropriate for the programs FEU is proposing. The 2012–2013 funding level was primarily set based on practical considerations relating to how much cost effective EEC FEU could realistically achieve. Rate impacts were only considered in the context of the setting an appropriate EEC amortization period.

The Panel welcomes FEU's commitment to consult the EEC Advisory Group regarding possible re-applications for additional EEC funding as a result of the clarification provided in this Decision.

4.4 Input Assumptions

This section will consider the following inputs used in the EEC cost effectiveness tests: avoided cost of gas, spillover assumptions and attribution of savings from codes and standards.

Avoided Cost of Gas

For the mTRC, FEU's avoided cost of gas is set by the DSM Regulations. During the Proceeding, BC Hydro issued an updated Integrated Resource Plan (IRP). In addition, there were subsequent changes to the DSM Regulations which removed the 50 percent factor which was previously applied to BC Hydro's LRMC (Ministerial Order 233, June 4, 2014). Therefore, the energy value of avoided gas is now equal to the LRMC of clean electric power. As the LRMC has not declined by 50 percent, this means the energy savings from avoided gas use has increased, leading to an increase in the mTRC. The result of this increase to the avoided cost of gas for the mTRC, which would improve the mTRC results of additional EEC programs, would not affect the EEC budget request as the mTRC can only be used for 33 percent of program cost and FEU are already bumping up against that cap. (T8:1389)

For the TRC, FEU have estimated their avoided cost of gas at $5.064/GJ. FEU submit that they have used a reasonable calculation of the avoided cost of gas and that no alternative methodology considered produced in a materially different result. FEU submit that in the interest of simplicity some immaterial components of the cost of gas were not included in the calculation. (FEI Non PBR Final Argument, pp. 105, 106; Exhibit B-11, BCUC 1.218.2)

Commission Determination

The Commission Panel accepts FEU's calculation of the cost of gas for the mTRC. However, the Panel directs FEU to include an update of the avoided cost of gas used for the mTRC in the next EEC Annual Report. This should reflect BC Hydro's LRMC included in the November 2013 Integrated Resource Plan, and the recent amendments to the DSM Regulations.

The Commission Panel accepts the calculation of the cost of energy for the TRC for the purpose of this Application. There is no evidence that the assumptions used to simplify the calculation of the avoided cost of gas used for the TRC has a meaningful effect on EEC investment. Further no Interveners expressed any concern that this is the case.

However, **the Commission Panel directs FEU to provide an estimate of the effect of each of its simplifying assumptions on the avoided cost of gas used for the TRC in the next EEC Expenditure Request.** This should include an estimate of the avoided FEU capacity cost and the effect on the avoided cost of gas estimate of (i) use of a weighted average for FEI's commodity rates for the most recent calendar year, (ii) use of the marginal or most expensive gas in FEU portfolio for the most recent calendar year using the current receipt point allocation, and (iii) use of the customer load profile to determine the avoided cost of gas for each customer class. In each case, FEU is to provide a detailed explanation of the methodology used.

<u>Spillover Effects</u>

In estimating energy savings from EEC programs, FEU currently accounts for free riders (persons who would have undertaken the demand-side measure without an incentive). FEU are requesting endorsement of the recognition of spillover effects (where a person undertakes a demand-side measure as a result of a program, but does not claim the incentive). FEU submit that spillover rates are difficult to measure, but not accounting for them is creating a lopsided view of FEU's EEC activity. FEU have included a 15 percent spillover rate for the Residential Energy Efficient Home Performance Program (LiveSmart BC), and plan to update the spillover rate based on the statistical evaluation of LiveSmart BC when it becomes available. (FEI Non PBR Final Argument, pp. 107–108)

BCSEA support FEU's request for endorsement of the recognition of spillover effects on a case-by-case basis where evaluation shows that spillover is occurring. (BCSEA Final Argument, p. 52)

Commission Determination

The Commission Panel agrees that, while spillover rates can be difficult to measure, excluding spillover estimates could result in the rejection of otherwise cost-effective EEC programs. **The Commission Panel therefore approves FEU's request for endorsement of the recognition of spillover effects on a case-by-case basis where evaluation shows that spillover is occurring.**

Given the lack of an evidentiary basis for the 15 percent spillover rate proposed for the Residential Energy Efficient Home Performance Program, the Panel declines to accept any spillover effect for this program at this time. We encourage FEU to submit for approval its estimate of the spillover effect based the statistical evaluation of LiveSmart BC when it becomes available.

Attribution of Savings from Codes and Standards

FEU request Commission endorsement of the concept of attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis where such an attribution can be supported. The DSM Regulation section 4(1.4) allow attribution where, in the Commission's opinion, the measure will increase the use of a regulated item with respect to which there is either a specified standard that has not yet commenced or a specified proposal. (Exhibit B-1-1, Appendix I, pp. 27–28)

Commission Determination

The Commission Panel encourages FEU to work with other parties to propose changes to codes and standards. While the Commission Panel endorses the concept of attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, where such an attribution can be supported, we are concerned that codes and standards measures can be so cost effective that they risk distorting the cost-effectiveness of the EEC portfolio as a whole.

4.5 Evaluation of FEU's EEC Expenditure Request

As noted previously, FEU request acceptance to spend approximately $35 million each year on EEC for 2014–2018. Pursuant to section 44.2(3) of the *Act*, the Panel will determine whether the proposed expenditures are consistent with the legal and the Cost Effectiveness frameworks previously laid out.

4.5.1 Review of Specific Program Portfolios

In reviewing specific program portfolios, the Panel will apply the legal framework and the cost effectiveness test to the entire portfolio, and, in addition, will examine new program additions proposed by FEU.

4.5.1.1 Residential

Table 4.3 Residential Programs

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
RESIDENTIAL (ALL PROGRAMS)	**54,902**	**30.8%**	**2,362,301**	**24.4%**	**0.73**	**2.05**	**1.18**	**7.50**
Energy Efficient Home Performance Program	7,901	4.4%	618,980	6.4%	1.09	3.08	2.96	3.07
* Furnace Replacement Program	16,705	9.4%	468,527	4.8%	0.51	1.45	0.93	9.64
Enerchoice Fireplace Program	5,823	3.3%	215,973	2.2%	1.57	4.45	0.98	8.88
Appliance Service Program	2,281	1.3%	0	0.0%	0.00	0.00	0.00	n/a
* ENERGY STAR® Water Heater Program	6,275	3.5%	207,105	2.1%	0.64	1.81	1.12	8.00
Low-Flow Fixtures	1,450	0.8%	192,375	2.0%	3.04	8.61	2.84	2.95
* New Home Program	4,677	2.6%	122,125	1.3%	0.41	1.16	1.01	9.19
* New Technologies Program	1,556	0.9%	24,216	0.2%	0.37	1.05	0.36	23.49
* Customer Engagement Tool for Conservation Behaviours	4,428	2.5%	513,000	5.3%	0.86	2.56	0.86	8.60
Financing Pilot	1,105	0.6%	0	0.0%	0.00	0.00	0.00	n/a
Non-Program Specific Expenses	2,700	1.5%	0	0.0%	0.00	0.00	0.00	n/a

(Source: Exhibit B-43, Attachment C)

FEU request $55 million in residential EEC funding over the PBR period, with 30 percent allocated to the Furnace Replacement Program. FEU submit that the Furnace Replacement Program is a cornerstone program in the EEC Residential Program Area, and have requested that the $2 million approved funding for the 2012 and 2013 pilot phase be increased to $3.3 million per year to fulfil customer demand. (FEI Non PBR Final Argument, p. 116)

BCSEA support FEU's request, and submit that they would also welcome an expansion of the Furnace Replacement program to include new end-of-life replacement furnaces if and when it is shown to be cost-effective. (BCSEA Final Argument, p. 53)

FEU also request $2.3 million over the PBR period for a Residential Appliance Service Program. While FEU do not attribute direct energy savings to this program, FEU submit that maintaining a furnace will result in energy savings and the program is no promoted in a way which suggests that participants will experience identifiable annual gas savings. FEU further submit that the program results in indirect energy savings by creating an opportunity to educate customers on energy saving behaviour and identifies furnace problems (including gas leaks). (FEI Non PBR Final Argument, pp. 109–110). BCSEA is supportive of this program. (BCSEA Final Argument, p. 52)

FEU also request $1.5 million over the PBR period for a New Technologies Program. FEU submit that the actual budget required will depend on whether cost-effective and feasible programs are identified from the Innovative Technology Program Area, and so funding may not be spent or conversely FEU could apply to the Commission for additional EEC funding. (FEI Non PBR Final Argument, p. 123)

BCSEA is supportive of this new program (BCSEA Final Argument, p. 53).

FEU further submit that "all EEC programs assume that the baseline condition is a certain level of natural gas use and that participants subsequently utilize a higher efficiency measure or measures which result in a reduction of natural gas consumption compared to the baseline condition". FEU state that, while they do not actively promote it, they do permit switching from another fuel source to natural gas for the ENERGY STAR® Water Heater Program and the EnerChoice Fireplace Program. However, with both of these programs FEU assume that participants switching from another fuel source would have switched to natural gas anyway under the baseline condition, but choose to upgrade to a higher efficient model of natural gas appliance than they would have selected under the baseline condition. (FEI Non PBR Final Argument, p. 111)

BCSEA supports the ENERGY STAR® Water Heater Program and the EnerChoice Fireplace Program (BCSEA Final Argument, p. 53).

Commission Determination

The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the New Technologies Program. The funding request appears reasonable and has the support of BCSEA.

In the last FEU Revenue Requirement Application, the Commission rejected a funding request for New Initiative Program Areas stating: "the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest." (Decision G-44-12, p. 167) FEU has provided no such detailed plan for this program. FEU is directed to submit a detailed plan for each program for approval prior to the expenditure of any funds related to these programs.

The Commission Panel has reviewed the Residential Program portfolio and applied the cost effectiveness framework we previously laid out. Although, on a portfolio basis, the TRC test result falls below one, the mTRC is favourable, being above one. Further, the programs within the portfolio provide an appropriate balance to allow customer access. As a checkpoint, we note that the UCT is also above one. **Accordingly, the Commission Panel accepts FEU's proposed Residential EEC Program portfolio.**

With regard to BCSEA's comments concerning the inclusion of end-of-life replacement furnaces, the Panel makes no determination at this time, but notes that FEU is free to bring forward such a request if, as and when this cost effectiveness can be demonstrated.

4.5.1.2 Low-Income

Table 4.4 FEU EEC 2014–2018 Gas Savings and Cost Effectiveness: Low Income

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
LOW INCOME (ALL PROGRAMS)	**15,223**	**8.6%**	**406,432**	**4.2%**	**0.96**	**2.36**	**0.73**	**11.97**
Energy Savings Kit	651	0.4%	136,063	1.4%	5.37	13.31	3.46	2.36
Energy Conservation Assistance Program	10,240	5.8%	118,065	1.2%	0.43	1.06	0.33	26.55
REnEW	405	0.2%	0	0.0%	0.00	0.00	0.00	n/a
Low Income Space Heat Top-Ups	394	0.2%	36,766	0.4%	2.99	7.34	3.17	2.84
Low Income Water Heating Top-Ups	77	0.0%	10,742	0.1%	1.42	3.48	3.34	2.54
Non-Profit Custom Program	1,931	1.1%	104,796	1.1%	2.79	6.83	2.07	4.40
Non-Program Specific Expenses	1,525	0.9%	0	0.0%	0.00	0.00	0.00	n/a

(Source: Exhibit B-43, Attachment C)

FEU requests $15.2 million in low-income EEC funding over the PBR period, with 67% of funding allocated to Energy Conservation and Assistance Program (ECAP). FEU consider ECAP to be their 'flagship' low-income program. ECAP is a comprehensive whole house low income program that

FEU conduct in partnership with BC Hydro and FortisBC, where low-income participants are not required to pay any costs. (FEI Non PBR Final Argument, pp. 112–113)

FEU also request $2.4 million in funding for new low-income programs: low income space and water heating top-up and a non-profit custom program. The top-up programs are based on the commercial programs, and provide an incentive that is about 30% higher than the regular program where buildings have a significant proportion of low-income residents. The non-profit custom program identifies and provides incentives for deeper energy-efficient retrofits to low income housing providers and not-for-profit associations. (FEI Non PBR Final Argument, pp. 121–122)

BCSEA are supportive of these new low-income EEC programs. (BCSEA Final Argument, p. 53)

Commission Determination

The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the low income space heating top-up, water heating top-up and the non-profit custom programs. The funding request appears reasonable and has the support of BCSEA.

In the last FEU Revenue Requirement Application, the Commission rejected a funding request for New Initiative Program Areas stating: "the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest." (Decision G-44-12, p. 167) FEU has provided no such detailed plan for any of these programs. FEU is directed to submit a detailed plan for each program for approval prior to the expenditure of any funds related to these programs.

The Commission Panel has reviewed the Low-Income EEC Program portfolio and applied the cost effectiveness framework we previously laid out. Although, on a portfolio basis, the TRC test result falls slightly below one, the mTRC is considerably above one. Further, the programs within the portfolio provide an appropriate balance to allow customer access. **Accordingly, the Commission Panel accepts FEU's proposed Low Income EEC Program portfolio.**

4.5.1.3 Commercial and Industrial

Table 4.5 FEU EEC 2014–2018 Gas Savings and Cost Effectiveness: Commercial and Industrial

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
COMMERCIAL (ALL PROGRAMS)	**54,144**	**30.4%**	**4,296,483**	**44.3%**	**1.07**	**3.05**	**1.72**	**5.03**
Space Heat Program	10,066	5.7%	848,671	8.8%	2.55	7.20	3.09	2.94
Water Heating Program	1,442	0.8%	215,798	2.2%	1.15	3.26	3.94	2.18
Commercial Food Service Program	2,448	1.4%	215,842	2.2%	1.81	5.11	2.42	3.56
Customized Equipment Upgrade Program	12,272	6.9%	771,502	8.0%	1.09	3.08	2.36	3.88
EnerTracker Program	964	0.5%	218,078	2.2%	1.57	5.04	1.51	4.42
* Continuous Optimization Program	9,214	5.2%	1,780,325	18.4%	0.81	2.35	1.95	3.92
Commercial Energy Assessment Program	2,339	1.3%	231,267	2.4%	1.00	3.02	0.72	10.11
Energy Specialist Program	9,882	5.6%	0	0.0%	0.00	0.00	0.00	n/a
Mechanical Insulation Pilot	16	0.0%	15,000	0.2%	5.76	16.25	30.45	0.30
Non-Program Specific Expenses	5,500	3.1%	0	0.0%	0.00	0.00	0.00	n/a
INDUSTRIAL (ALL PROGRAMS)	**12,896**	**7.2%**	**2,192,299**	**22.6%**	**3.08**	**8.67**	**4.15**	**2.05**
Industrial Optimization Program	9,148	5.1%	1,552,971	16.0%	2.90	8.18	3.89	2.17
Specialized Industrial Process Technology Program	2,438	1.4%	639,328	6.6%	4.66	13.12	7.29	1.19
Non-Program Specific Expenses	1,310	0.7%	0	0.0%	0.00	0.00	0.00	n/a

(Source: Exhibit B-43, Attachment C)

FEU request $54.1 million in commercial EEC funding over the PBR period. Included in this request is $16,000 for a new program (Mechanical Insulation Pilot) which provides thermal insulation for bare heating pipes, valves, and fittings in existing multi-unit residential buildings. FEU submit that the results of the pilot could provide the basis for a cost-effective commercial EEC program. (FEI Final Argument Non PBR Issues, pp. 120, 121)

BCSEA are supportive of this new program. (BCSEA Final Argument, p. 53)

FEU also request $12.9 million in industrial EEC funding over the PBR period. Included in this request is $2.4 million for a new program: Specialized Industrial Process Technology Program. This is aimed at process heat in the manufacturing sector and includes the following measures: steam distribution, process boiler system, wood drying process. (FEI Final Argument Non PBR Issues, p. 119)

BCSEA are supportive of this new program. (BCSEA Final Argument, p. 53)

Commission Discussion

The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the both the new Mechanical Insulation Pilot program and the new Specialized Industrial Process Technology Program.

However, in the last FEU Revenue Requirement Application, the Commission rejected a funding request for New Initiative Program Areas stating: "the Commission Panel finds that it would need to have a more detailed plan for such programs, including information on how a particular program will be developed, tested (perhaps through pilot programs), implemented and evaluated, before it can be assured that the program is in the public interest." (Decision G-44-12, p. 167) FEU has provided no such detailed plan for either of these programs. FEU is directed to submit a detailed plan for each program for approval prior to the expenditure of any funds related to these programs.

The Commission Panel has reviewed the Commercial EEC Program portfolio and applied the cost effectiveness framework we previously laid out. On a portfolio basis, both the TRC and the mTRC test results are above one. Further, the programs within the portfolio provide an appropriate balance to allow customer access. As a checkpoint, we note that the UCT is substantially above one. **Accordingly, the Commission Panel accepts FEU's proposed Commercial EEC Program portfolio.**

The Commission Panel has reviewed the Industrial EEC Program portfolio and applied the cost effectiveness framework we previously laid out. On a portfolio basis, both the TRC and the mTRC test results are above one. Further, the programs within the portfolio provide an appropriate balance to allow customer access. As a checkpoint, we note that the UCT is substantially above one. **Accordingly, the Commission Panel accepts FEU's proposed Industrial EEC Program portfolio.**

4.5.1.4 Other

Table 4.6 FEU EEC 2014–2018 Gas Savings and Cost Effectiveness: Other Programs

Program and Service Territory	Utility Expenditures ($1000s)		Gas Savings, Net (GJ)		Benefit Cost Tests			
	2014-2018	% of Total	2014-2018	% of Total	TRC (Ratio)	MTRC (Ratio)	Utility (Ratio)	Utility ($/GJ)
CONSERVATION EDUCATION AND OUTREACH (ALL PROGRAMS)	12,000	6.7%	0	0.0%	0.00	0.00	0.00	n/a
Residential Education Program	4,950	2.8%	0	0.0%	0.00	0.00	0.00	n/a
Commercial Education Program	2,250	1.3%	0	0.0%	0.00	0.00	0.00	n/a
School Education Program	3,600	2.0%	0	0.0%	0.00	0.00	0.00	n/a
Non-Program Specific Expenses	1,200	0.7%	0	0.0%	0.00	0.00	0.00	n/a
INNOVATIVE TECHNOLOGIES (ALL PILOTS)	6,086	3.4%	435,173	4.5%	1.75	4.93	2.29	3.92
ENABLING ACTIVITIES (ALL ACTIVITIES)	22,740	12.8%	0	0.0%	0.00	0.00	0.00	n/a

(Source: Exhibit B-43, Attachment C)

FEU request $12 million in Conservation Education and Outreach (CEO) programs over the PBR period. This includes education programs that meet the adequacy requirements of the DSM Regulations.

This amount includes $6 million in innovative technology pilot funding over the PBR period to evaluate market-ready technologies and conduct pilot studies to validate manufacturer's claims related to equipment and system performance. Technologies being evaluated include condensing unit heaters and combination space/water heating units. (Exhibit B-1-1, Appendix I, Attachment 1, pp. 84, 96–99)

In addition, FEU requests $22.7 million in funding for 'Enabling Activities', of which $17.5 million ($3.5 million/year) represents the cost of FEU labour costs coded to EEC and $2.5 million ($500,000/year) for an 'Efficiency Partners Program' which develops a contractor network to promote FEU EEC programs and energy-efficiency messaging. In addition $35,000/year is budgeted for codes and standards, $500,000 for a 2015 update of the Conservation Potential Review and $300,000 for a 2014-2015 market saturation study. By way of comparison, for 2012, Enabling Activates included only the Efficiency Partners Program ($334,000 spent in 2012) and Codes and Standards ($15,000 spent in 2012). (Exhibit B-1-1, Appendix I, Attachment 1, pp. 103–105; FEU 2012 EEC Annual Report, p. 81).

For the Efficiency Partners Program, FEU submit that if contractors are not supportive of EEC investments/behaviours then it is unlikely that the customer will be. FEU also state that funding includes energy efficiency training as required by the DSM Regulations, and that the codes and standards budget was derived independent of any consolation with government. (Exhibit B-1-1, Appendix I, Attachment 1, p. 104; Exhibit B-11, BCUC 1.232.2.1, 1.232.3).

Commission Determination

The Commission Panel has reviewed the proposed innovative technology pilot funding and applied the cost effectiveness framework we previously laid out. On a portfolio basis, both the TRC and the mTRC test results are above one. Further, the programs within the portfolio provide an appropriate balance to allow customer access. As a checkpoint, we note that the UCT is substantially above one. **Accordingly, the Commission Panel accepts FEU's Innovative Technologies EEC Program portfolio.**

The Commission Panel accepts the Conservation Education and Outreach and the Enabling Activities EEC programs.

To aid transparency, FEU are directed to allocate 'FEU labour costs coded to EEC' to its EEC programs, with the exception of costs related to Evaluation, Measurement & Verification which should be shown separately. FEU should include in the next EEC Annual Report a description of the cost allocation methodology used, and any differences between the methodology proposed and that used in the 2012–2013 Application. The Panel considers that this approach will better support a review of the effectiveness of EEC programs and will better enable a comparison of EEC funding requests by program to funding allocated and spent in previous years.

The Panel understands the logic behind the development of a contractor network, but has concerns that it may include expenses better characterised as marketing and that it may inadvertently result in load building. **FEU are directed in the next EEC Annual Report to explain how it ensures the focus of the contractor network program is on reducing overall gas consumption by customers.**

4.5.2 Programs for Rental Accommodation

FEU submit that they have met the requirements of the DSM Regulations with regard to rental accommodation as all of FEU's residential programs are available to renters, and the DSM Regulations do not require programs *exclusively* for rental accommodation. FEU state that they have identified only three EEC programs in other jurisdictions exclusively available to rental accommodations. (FEI Final Argument Non PBR Issues, pp. 95–96)

BCSEA submits that FEU's EEC plan meets the "adequacy" requirements. BCSEA considers that "adequacy" under the DSM Regulation is an evolving standard, and as experience is gained and EEC programs mature the required programs should be expected to be more effective. (BCSEA Final Argument, p. 50)

Commission Determination

The Commission Panel does not support FEU's argument that having generic EEC programs that renters can access meets the requirements of the DSM Regulations. This logic would not be applied to adequacy requirements for low-income customers, and so should not be applied here.

The Commission Panel therefore directs FEU to, by the end of 2015 and within the existing EEC funding envelope, file with the Commission one or more EEC programs intended specifically to address the unique market barriers to energy efficiency faced by renters (for example, the landlord tenant split-incentive). This does not require that only renters access the program, for example the program could instead be focused on landlords. The key outcome, however, is that the program is intended specifically to improve the energy efficiency of rental accommodation.

4.5.3 Five Year EEC Request

FEU request the Commission accept the EEC expenditures request for a five-year period (2014–2018). FEU submit that acceptance of five years of expenditures would establish certainty in the market, such that contractors and manufacturers will be better able to support EEC initiatives, and that it will allow FEU to take advantage of program momentum and dedicate time otherwise spent on regulatory work to program development, refinement and operation. FEU further submit that other utilities they surveyed had an average DSM funding approval period of 3.4 years (FEI Final Argument Non PBR Issues, pp. 83–84)

BCSEA note that the proposed five-year test period is a relatively long time, during which many changes could occur affecting EEC programs (BCSEA Final Argument, p. 46). However, BCSEA support the five-year expenditure period subject to FEU's willingness and ability to re-apply to the Commission for increased funding if circumstances warrant (BCSEA Final Argument, p. 48).

Commission Determination

The Commission Panel approves FEU's request for a five-year expenditure period. In making this determination, the Panel notes that the next CRP is expected by 2016, and at that time, FEU is free to file a new EEC application if circumstances warrant.

4.5.4 Setting the Total EEC Funding Envelope

FEU submit that the 2014–2018 EEC expenditure schedule is an extension of its previously approved 2012–2013 EEC plan (FEI Non PBR Final Argument, p. 78).

Table 4.7 Portfolio Level EEC Cost Effectiveness Results

Program Area and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios			
	2014	2015	2016	2017	2018		TRC	Portfolio*	Utility	Participant
ALL PROGRAMS										
FEI	637,255	1,255,547	1,733,589	2,265,196	2,787,418	21,247,479	0.94	1.36	1.32	2.15
FEVI	66,693	136,195	204,155	270,295	336,344	2,798,187	1.04	1.31	1.39	3.74
Total	**703,948**	**1,391,743**	**1,937,743**	**2,535,491**	**3,123,762**	**24,045,666**	**0.95**	**1.35**	**1.33**	**2.33**

* Includes the MTRC adder for programs that require it (i.e. TRC/MTRC hybrid)

(Source: Exhibit B-43, Attachment A)

FEU submit that, although FEU have taken the Commission's 2012-2013 Approved levels as a guide for overall expenditure levels, FEU's proposed level of expenditures is cost effective on a portfolio basis and sufficient to pursue all cost-effective EEC programs in FEU's Conservation Potential Review (CPR). FEU also submit that they consulted with members of the EEC Advisory Group and there was no indication that any major "course corrections" were necessary, and that this supports the continuation of existing levels of expenditures rather than a dramatic shift. (FEI Non PBR Final Argument, p. 78)

FEU state that, if FEU were to increase the funding limit by 10 percent or 50 percent, they would not develop or implement any new programs or expand existing programs. (FEI Non PBR Final Argument, pp. 79–80)

FEU further submit that while increasing expenditures on programs already offered may increase participation, based on actual experience existing spending levels are not expected to constrain participation. Should it appear over the test period that existing cost effective programs warrant expansion, or that more cost-effective EEC activity could be deployed, FEU could re-apply to the Commission for additional EEC funding. FEU submit that an updated CPR (budgeted for in 2015) will provide a new starting point for the EEC budget (FEI Non PBR Final Argument, pp. 80–82)

BCSEA agrees that FEU's proposed spending levels are not unreasonable, and that the EEC plan is in the public interest and should be approved. However, BCSEA submits that the evidence on record strongly reflects the potential availability of additional cost-effective EEC opportunities. (BCSEA Final Argument, p. 46)

BCPSO submit that FEU's proposed EEC spending appears excessive when compared to actual 2012 EEC spending and is unlikely to be achieved. Accordingly, BCPSO submits that the proposed amounts should be reduced." (BCPSO FEI Non PBR Final Argument, p. 6)

Commission Determination

The Commission Panel has previously accepted FEU's residential, commercial, industrial and low income EEC portfolios, including the relative allocation between these program classes. Further, the Panel has approved FEU's proposed five-year EEC spending period. Reviewing FEU's overall EEC portfolio, the Panel remains persuaded that FEU's proposed spending levels pass portfolio level cost effectiveness tests and are not unreasonable. **Accordingly, the Commission Panel approves FEU's EEC expenditure of $34.353 million for 2014; $36.537 for 2015; $35.839 for 2016; $35.388 for 2017 and $35.874 for 2018.**

4.6 Other Issues

4.6.1 <u>Movement of Funds between Categories</u>

FEU propose that program funding transfer rules follow the same process approved by the Commission for the 2012–2013 test period, including permitting funding transfers under 25 percent from one approved Program Area to another. In this Application, FEU are also requesting that they be permitted to launch new programs without pre-approval from the Commission provided the new program complies with the DSM Regulations, has not been previously rejected by the Commission and is funded by a transfer of funds within an approved Program Area. FEU submit that the new funding transfer rule will allow it to take advantage of opportunities that emerge over the course of the PBR period. (Exhibit B-1-1, Appendix I, p. 20)

BCSEA supports the proposed new funding transfer rule. (BCSEA Final Argument, p. 54)

Commission Determination

The Commission Panel approves FEU's request that program funding transfer rules follow the same process approved by the Commission for the 2012–2013 test period. However, the Panel denies FEU's request to transfer funds to new programs not yet identified without pre-approval by the Commission.

The Commission Panel recognizes that FEU seek to continually revise and update their EEC plan to improve its effectiveness. Nonetheless, the Panel does not consider that a request to the Commission for pre-approval of a new program is unnecessarily burdensome. The Panel requires that when FEU identifies and develops a new program it wants to implement, FEU must demonstrate through a written request to the Commission that the new program results in a net long-term improvement in portfolio effectiveness and/or is required to ensure appropriate balance in terms of different customers' ability to access EEC programs. The filing should include a business plan for the new program, and should identify where the funds will be transferred from.

4.6.2 Amortization Period

In the 2012-2013 FEU RRA Decision, the Commission stated that it was not persuaded that a 10-year EEC amortization period was necessarily appropriate and requested additional information detailing the rate impact of alternative amortization scenarios in the next EEC application (Commission Order G-44-12, pp. 184–185).

FEU submit that a 10-year amortization period is supported by estimated average measure life weighted by savings of 13.2 years and that a shorter amortization period would result in significant rate increases for customers. It states that a five-year amortization period would result in delivery rate increases of approximately two percent for FEI customers in 2014. (FEI Non PBR Final Argument, pp. 136–137)

To address concerns that EEC funding may be underspent, FEU propose to maintain the 2012–2013 approved approach that only $15 million of the requested annual EEC budget be added to the EEC rate base each year of the PBR period, with any additional EEC spend being captured in an EEC non-rate base deferral account attracting AFUDC. In this Application, FEU are requesting approval to transfer any new amounts accumulated in the non-rate base EEC deferral account to FEU rate base EEC deferral account in the following year. (Exhibit B-1-1, Appendix I, p. 9, 31)

BCSEA supports FEU's proposed continuation of the financial treatment of EEC expenditures and finds the 10 year amortization period satisfactory. (BCSEA Final Argument, p. 55)

Commission Determination

The Commission Panel is of the view that section 60(i)(b)(ii) of the UCA, which requires that the utility receive a fair and reasonable return on any expenditure made to reduce energy demand, is satisfied as long as the carrying cost for any such expenditure is the utility's WACC. The length of the amortization period should be determined based on criteria such as rate impact and matching the benefits of EEC with the costs.

The Panel is prepared to accept the requested amortization period of 10 years at this time, primarily on the basis of rate impact concerns. However, the Panel notes that a shorter amortization period could decrease costs for customers over the longer term while still providing the utility with a fair return. The Panel notes that this issue was addressed in a 2006 CAMPUT report titled 'Demand-Side Management: Determining Appropriate Spending Levels and Cost-Effectiveness Testing', which states:

> "Most utilities and regulators prefer the practice of expensing energy efficiency costs; in the long run, this approach costs less than capitalizing—deferring and amortizing—costs. … The carrying cost (at the utility average cost of capital, 7-9% these days) of the unamortized balances adds cost to consumers, quite a lot if the amortization period is long. … Once this practice starts, it is hard to convert to expensing, again due to rate impact concerns." (FBC PBR 2014-2018, Appendix A to Exhibit C10-7, Appendix A, p. 34)

The Commission Panel recommends that the appropriateness of a shorter amortization period be reviewed at the time of the next FEU EEC Application. **The Commission Panel directs FEU to include in the next FEU EEC Application an analysis of the rate impact of a reduction in the EEC amortization period to eight years and to five years.**

The Commission Panel approves FEU's request to (i) continue the EEC accounting treatment approved for 2012–2013 and (ii) to transfer any new amounts accumulated in the non-rate base EEC deferral account to FEU rate base EEC deferral account in the following year.

4.6.3 Evaluation, Measurement and Verification Approach

FEU have filed an EEC Evaluation Plan which presents the studies and timing for the Evaluation, Measurement & Verification (EM&V) activities for the PBR Period. EM&V activities are split between evaluation activities, and measurement and verification activities. Evaluation activities are conducted to look at a program as a whole to determine its effectiveness. Measurement and Verification (M&V) studies are conducted to assess pilot programs, demonstration projects and custom programs. (FEI Non PBR Final Argument, p. 127)

FEU note that the EM&V budget, at around 4 percent of the EEC portfolio, appears at the low end of the range of percentage of spending on DSM activity among other utilities, but submit that this is because EM&V spending lags behind program spending and there has been a ramp up in EEC spending in recent years. FEU expect annual EM&V spending to increase over the PBR Period. (FEI Non PBR Final Argument, p. 128; Exhibit B-24, BCUC 1.371.6)

The proceeding raised some concern as to whether there is a conflict of interest in FEU both undertaking the EEC programs and conducting the evaluation of the programs' success. FEU submit that this issue is addressed by organization separation between EEC program staff and the EM&V staff, an annual review of the EEC function by FEU's Internal Audit group and the development of an EM&V Framework which guides EM&V activities. FEU further submit that external stakeholders, such as members of the EEC Advisory Group, may request to view final evaluation reports. (FEI Non PBR Final Argument, pp. 129–130)

In addition, FEU submit that they rely heavily on independent third party consultants to conduct the majority of the EM&V activities, and that further reviews, such as ones conducted by third parties retained by the Commission, would place an unnecessary burden on rates. (FEI Non PBR Final Argument, pp. 130–131)

BCSEA submits that FEU's use of third party consultants, internal separation and external stakeholders to segregate EM&V activities from EEC implementation influences is an acceptable EM&V approach at this time. BCSEA concurs with FEU that an independent review of FEU's EM&V would not be money well spent (BCSEA Final Argument, p. 54).

Commission Discussion

The Commission Panel is satisfied that FEU's approach to EM&V approach sufficiently protects ratepayer interests and therefore is acceptable at this time. Further, we concur with BCSEA and

FEU that an independent review of FEU's EM&V may not be cost effective. Accordingly the Panel declines to direct a review of FEU's EM&V at this time.

4.6.4 EEC Fund Administration – TES Projects

Throughout FEU 2012 Alternative Energy Solutions (AES) Inquiry and the 2012-2013 FEU Revenue Requirement proceeding the Commission heard concerns regarding the potential for preferential treatment in the administration of EEC funds to customers who choose FAES over other third party energy providers for projects with a thermal energy component. In the AES Inquiry the Commission Panel directed FEU to bring forward a proposal for mechanisms for approval and administration of funds by a neutral third party where FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that funding. (2012 Commission AES Inquiry Report, p. 87)

In response to this directive, FEU submitted a proposal from Price Waterhouse Coopers (PWC) to review applications and administer EEC funds for all projects with a third party thermal energy component, whether the provider is FAES or another provider (Exhibit B-1-1, Appendix I, Attachment 4).

A concern was raised by COC that, in some cases, the PWC proposed process would still have customers apply first to FEU for the EEC funding and that this could result in a conflict of interest (COC Final Argument, pp. 2–3). This was disputed by FEU, who submit that FEU would ask customers if they are or will be using a thermal energy provider, and if the answer is yes, FEU would be immediately removed from the approval and administration of EEC funds. FEU also note that FEI personnel with access to customer information do not communicate with FEI personnel working on FAES thermal energy projects regarding customer information, EEC applications, or any relevant information that is not in the public domain (FEI Non PBR Reply, p. 45).

BCSEA supports FEU's proposed approach as a practical and efficient way to accomplish fairness (BCSEA Final Argument, p. 56).

FEU also request approval to place the expenditures related to the third party review (estimated at an annual cost of $140,000 to $260,000) in the non-rate base EEC deferral account that attracts AFUDC (FEI Non PBR Final Argument, p. 142). BCSEA supports this approach (BCSEA Final Argument, p. 56). COC, however, submits that the cost of the EEC third party review should be borne by the FEI/FAES shareholder and not the natural gas ratepayer as FEI has chosen to place itself in a position of potential conflict of interest (COC Final Argument, p. 5).

FEU reply that the PWC proposal is in direct response to a Commission direction and there is no basis on which the Commission could deny cost recovery (FEI Non PBR Reply, p. 47).

The PWC proposal also includes an initial backward looking review of EEC grants involving a thermal energy component that have been awarded in the past two years since inception of the program, and proposes that this backward looking review is undertaken an annual basis. PWC estimates the additional cost for this initial annual review component will be $25,000. (Exhibit B-1-1, Appendix I, Attachment 4, p. 6)

Commission Determination

The Commission Panel approves the third-party administration portion of the PWC proposal put forward by FEU. The Commission is satisfied that the proposed mechanism meets the Commission's directive in the 2013–2103 FEU RRA decision and agrees with FEU and BCSEA that the proposed process is a practical way to accomplish fairness and reduce the potential bias and influence in administering EEC funds to customers who have projects with a third-party thermal energy component.

However, the Panel does not approve the initial and subsequent annual backward-looking review portion of the PWC proposal. The Panel considers this is an unnecessary expenditure as the Panel is satisfied that, once implemented, PWC's process to review and administer EEC funds for projects with a thermal component will adequately address the potential for FEU to use EEC funds to promote FAES over its thermal competitors.

The Commission Panel denies FEU's request to place the actual expenditures from PWC's administration of EEC funds for projects with a thermal energy component in the EEC non-rate base deferral account that attracts AFUDC. In this Decision, the Panel has previously directed that any expenses related to TES not be recovered from FEI ratepayers. These expenses must instead be recovered from TES customers.

5.0 SUMMARY OF DIRECTIVES

This Summary is provided for the convenience of readers. In the event of any difference between the Directions in this Summary and those in the body of the Decision, the wording in the Decision shall prevail.

1.	The Commission Panel determines that it is appropriate to render a decision based on the substantial evidence before it and not move to a further process on the design of the PBR.	13
2.	The Commission Panel directs FEI to provide a detailed review of the historical expenditures of Capital and O&M for FEVI and FEW and a formal proposal for including FEVI and FEW within the PBR.	17
3.	In order to realize the full benefits of a five-year term, the Panel directs the term be extended through the end of 2019.	27
4.	Considering the potential for a significant impact on the I-X formula resulting from this, the Commission Panel denies Fortis' proposal to rely on forecast data in the determination of the I-Factor.	33
5.	The Commission Panel determines that the I-Factor used in the formula is the actual index results of the previous year.	33
6.	The Commission Panel has reviewed the evidence and determines that the CPI-BC as calculated by Statistics Canada and BC-AWE indexes are most appropriate for use in this PBR.	34
7.	The Commission Panel approves a 55 percent labour weighting for use in the O&M formula for FEI and FBC.	34
8.	The Commission Panel determines that the 55 percent to 45 percent labour to non labour ratio for use in the capital formula for FBC and FEI is reasonable and appropriate.	35
9.	The Panel finds that the method for calculating the growth rate of an output level index is not an appropriate approach. Accordingly, the output trend calculated by B&V cannot be relied upon.	46
10.	The Panel finds B&V's approach of calculating the growth in the output measures is not an appropriate approach to the calculation of the output trend.	47

11.	The Panel finds that B&V’s method of calculating the output trend cannot be relied upon.	47
12.	The Panel finds that B&V’s method of calculating the input trend cannot be relied upon.	51
13.	The Panel finds that B&V’s cost based input methodology understates the TFP trend.	52
14.	The Panel finds that a short study period is not appropriate.	54
15.	The Panel finds that a study period should at least be long enough to smooth out any significant short term economic trends.	54
16.	The Commission Panel finds that B&V’s TFP trend results may require significant adjustment to allow for the short study period B&V used, particularly in the case of the gas utility study.	54
17.	Given the materiality of this issue, the Panel finds that B&V’s use of arithmetic growth rates results in a substantial understatement of the TFP trend.	56
18.	Given the number of shortcomings in B&V’s methodology and the errors that arise from these shortcomings, the Panel does not accept B&V’s study results.	58
19.	The Panel finds PEG’s approach to using input cost indexes to calculate input quantities is acceptable.	65
20.	In the absence of specific information of the labour mix at each utility, the Panel finds an assumption of a labour mix to be reasonable.	67
21.	The Panel finds that no adjustment to PEG’s study results are necessary to account for any potential bias introduced by its labour input index assumptions.	67
22.	The Panel using its best judgement finds a reduction of 0.06 percent to the MFP trend results from PEG’s gas utility productivity study to be appropriate.	69
23.	The Panel finds that no adjustments are necessary to account for PEG’s capital costing approach.	72
24.	The Panel declines to make any adjustments to the study results to account for negative salvage.	73
25.	The Panel finds that B&V’s proposed calibration is not required.	75

26.	The Commission Panel agrees with CEC and IRG and finds the PEG study results to be the best available evidence in this proceeding.	80
27.	The Panel considers these results to be an appropriate basis to set an X-Factor for the six-year PBR term.	80
28.	Considering the PEG study results and the adjustment to the gas study previously determined by the Panel to be required, the Commission Panel finds a TFP trend of 0.93 percent for electric utilities and 0.90 percent for gas utilities is appropriate.	81
29.	The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.	82
30.	In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study.	82
31.	Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	82
32.	Considering the stretch factor evidence before the Commission Panel, we determine a stretch factor of 0.2 percent for FEI and 0.1 percent for FBC to be appropriate.	86
33.	The Panel is unable to approve the X-Factor as applied for.	90
34.	If significant capital is to be excluded from the formula, the Commission Panel finds that the X-Factor requires an upward calibration.	90
35.	The Panel will not apply any adjustments at this time, but directs that this issue be revisited when a further determination on the dollar threshold is made.	91
36.	The Commission Panel has determined the following X-Factors should be applied to Fortis' proposed PBR formulas for the PBR term:	91

Table 5.1 Approved X-Factors

Utility	TFP	Stretch Factor	X-Factor
FBC	0.93	0.1	1.03
FEI	0.90	0.2	1.10

37.	The Panel finds it necessary to include exogenous factors as part of the Companies' PBR plan in order to protect both the ratepayers and the shareholders. The Commission Panel therefore establishes the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment: 1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility; 2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived; 3. The impact of the event was unforeseen; 4. The costs must be prudently incurred; The costs/savings related to each exogenous event must exceed the Commission-defined materiality threshold.	97
38.	The Commission Panel finds that a materiality threshold is a necessary component of the exogenous factor criteria as it meets the Companies' guiding PBR principle of reducing the regulatory burden over time.	98
39.	The Commission Panel finds that materiality thresholds for FEI and FBC, amounting to 0.5 percent of each Company's 2013 Base O&M, are appropriate.	99
40.	The Commission Panel directs the Companies to provide materiality threshold calculations as part of their Compliance Filings. These calculations must also reflect all changes to each Company's 2013 Base O&M directed in this Decision.	99
41.	The Commission Panel further directs that exogenous events not be aggregated.	99
42.	Thus, the materiality threshold applies both to exogenous savings as well as to exogenous costs. That is any event resulting in savings must meet the criteria before it is accepted as an exogenous savings.	99
43.	The Panel directs Fortis to include a proposal for the appropriate recovery mechanism as part of any exogenous factor applications.	100
44.	The Commission Panel approves FBC and FEI's proposed flow-through items with the exception of the items discussed below.	107
45.	The Commission Panel directs the Companies to flow-through only the Insurance Premiums portion of Insurance Expense.	107

46.	The Panel directs the Companies to update the flow-through expenses in the Final Compliance Filings so that only the Insurance Premiums are included in the Insurance Expense flow-through.	107
47.	The Commission Panel rejects Fortis' proposal to apply the 50/50 ESM to any of the flow-through revenues/costs and directs that no flow-through items be subject to the ESM mechanism.	107
48.	The Commission Panel denies FBC's request to establish the Tax Variance deferral account and the Insurance Expense Variance deferral account.	111
49.	The Commission Panel denies FBC's request to establish the Property Tax Variance deferral account and the Interest Expense Variance deferral account.	111
50.	The Commission Panel directs FBC to true-up these costs each year.	112
51.	Accordingly, the Commission Panel directs FEI to discontinue the usage of the following deferral accounts: the Tax Variance deferral account, the Property Tax Variance deferral account, the Insurance Expense Variance deferral account and the Interest Expense Variance deferral account. For the deferral accounts which have a one-year amortization period – the Insurance Expense Variance deferral account and the Tax Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into 2014 rates and then discontinue the use of these accounts. For the deferral accounts which have a three-year amortization period – the Property Tax Variance deferral account and the Interest Expense Variance deferral account – the Panel directs FEI to amortize the ending 2013 balances into rates over three years and then discontinue these accounts. FEI must not add any additional variances to these four deferral accounts commencing January 1, 2014.	112
52.	The Commission Panel directs FEI to true-up these costs each year.	112
53.	Given the lack of evidence concerning the quantum of the required adjustment, the Panel applies its best judgement and directs that the Growth Term be reduced by 50 percent. Further, to eliminate the possibility of potential bias, the Panel directs that the ratio be calculated as the ratio of the number customers or service line additions one year previous, to the number of customers or service live additions two years previous.	122
54.	The Commission Panel approves Growth Terms of 0.5 * (SLAt-1/SLAt-2) for FEI's growth capital and 0.5 * (ACt-1/ACt-2) for all other cases.	122

55.	The Commission Panel determines that the inclusion of a symmetric ESM is beneficial to both Fortis and its customers.	124
56.	Given these reasons, the Commission Panel denies the Fortis request for the proposed ECM methodology.	132
57.	The Commission Panel determines that the following steps are required in order for Fortis to receive approval for an ECM initiative; 1. ECMs will in most cases be handled within the context of the Annual Review although where warranted, the Commission could consider an ECM measure within the year. 2. For each proposed initiative for which the benefits are expected to extend beyond the term of the PBR, Fortis will file an ECM proposal providing a description of the proposal, its timing, costs and benefits, and reasoning as to why it is appropriate and how long benefits should be paid. 3. Parties will have the opportunity to comment on the proposal.	132
58.	Considering these issues the Commission Panel determines that there is a need for consequences to be tied to the failure to achieve reasonable performance on defined SQIs.	138
59.	The Commission Panel determines that the incentives earned must be linked to the achievement of service quality standards.	139
60.	The Commission Panel finds that they are not a balanced set of indicators covering reliability, responsiveness to consumer needs and providing for the safety of the public.	147

<table>
<tr><td>61.</td><td>Within these categories the Commission Panel approves the following SQIs proposed by Fortis:
Safety
Emergency Response Time
Telephone Service Factor (emergency)
Customer needs
First Contact Resolution
Billing Index
Meter Reading Accuracy
Telephone Service Factor (non-emergency)
Meter Exchange Appointment
In addition, the Commission Panel directs that a number of Fortis' proposed informational SQIs be re-classified as benchmarked SQIs. These include:
Safety
All Injury Frequency Rate
Public Contact with Pipelines
Reliability
SAIDI (weather normalized) FBC only
SAIFI (weather normalized) FBC only
Further, the Panel approves the following informational indicators:
Customer Satisfaction Index
Telephone Abandon Rate
and we direct Fortis to reinitiate the following informational indicators:
Generator Forced Outage Rate
Transmission Reportable Incidents
Leaks per KM of Distribution System Mains</td><td>148</td></tr>
<tr><td>62.</td><td>The Commission Panel considers the performance benchmark of 97.7 percent (FEI Exhibit B-1-1, Appendix D7, p.6) to be appropriate as it reflects current performance and directs Fortis to set the SQI benchmark at this level for the purposes of the PBR. The Panel further direct that the FBC Emergency Response benchmark be set at 93 percent, which reflects the average Emergency Response achieved over the 2010 to 2012 period.</td><td>150</td></tr>
<tr><td>63.</td><td>The Commission Panel approves the reduction to 70 percent.</td><td>150</td></tr>
<tr><td>64.</td><td>The Commission Panel approves the Fortis proposed benchmarks for all other proposed benchmarked SQIs.</td><td>151</td></tr>
</table>

65.	For all new benchmarked SQIs the Panel directs Fortis to rely upon a 3 year average for 2010, 2011 and 2012 in calculating its performance benchmark.	151
66.	The Commission Panel directs Fortis to utilize the SQIs set out below for the PBR period. The Panel considers these to be balanced and collectively address service reliability, safety and customer needs.	151
67.	Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.	154
68.	The Panel determines it to be appropriate to use a three-year average of 2010, 2011 and 2012 to set the benchmark around which a range can be established and we direct the use of this approach in setting benchmarks for the SQIs that the Panel has directed to be modified or added.	154
69.	The Panel directs the Companies, in consultation with stakeholders, to develop a performance range for each SQI covering the range of scores where performance would be found to be satisfactory.	155
70.	In providing its recommendations the Companies are directed to forward to the Commission any comments on the recommendations provided to them by stakeholders and Commission staff.	155
71.	Where the parties are unable to agree on a resolution to mitigate the problem or the parties consider further process to be warranted, the Panel directs them to refer the matter to the Commission.	155
72.	The Panel directs that the maximum reduction to the incentive earnings will be an adjustment to the earnings sharing mechanism to reflect a 60 percent ESM share to the customer rather than the standard 50 percent.	156
73.	In the Commission Panel's best judgement, a multi-pronged trigger strikes an appropriate balance between incenting the Companies to find efficiencies and savings and protecting the interest of the ratepayers. The Panel directs that an off-ramp be triggered if earnings in any one year varies from the approved ROE by more than +/- 200 basis points (post sharing). The Commission Panel further directs that should earnings average more than +/- 150 basis points (post sharing) from the approved ROE for two consecutive years the off-ramp will be triggered.	160
74.	The Commission Panel finds that providing a specific definition of what constitutes a "sustained serious degradation" in service is not practical.	163

75.	Parties are directed to review the concept of "sustained serious degradation" of service levels at each Annual Review and provide recommendations to the Commission as to whether additional considerations to those set out above are appropriate.	164
76.	The Commission Panel finds that it is appropriate to exclude some capital projects from the capital formula spending envelope.	177
77.	The Panel finds this an appropriate mitigation, providing the dead-band trigger results in a rebasing of the capital formula, and that in this eventuality, the rebased amount be applied to the subsequent year's formula.	178
78.	In summary, the Panel finds that the current CPCN exclusion criteria as proposed are not appropriate.	180
79.	Until such time as any further determination is made concerning capital exclusion, the Panel approves the current CPCN exemption threshold as the threshold for exclusion for both utilities as applied for.	182
80.	The Panel finds that a more extensive Annual Review process is necessary to build trust among all stakeholders and to ensure the PBR Plan functions as intended.	185

81.	The Commission directs that the Annual Review process include the following: 1. Evaluation of the operation of the PBR Plan in the past year(s) and identification by any party of any deficiencies/concerns with the operation of the PBR plan that have become apparent. Parties are expected to put forward recommendations with how to deal with such concerns. 2. Review of the current year projections and the upcoming year's forecast (FEI Exhibit B-1, p. 78, 79; FBC Exhibit B-1, p. 71, 72). For further clarity, these items are listed below: a. Customer growth, volumes and revenues; b. Year-end and average customers, and other cost driver information including inflation; c. Expenses (determined by the PBR formula plus flow-through items); d. Capital expenditures (as determined by the PBR formula plus flow-through items); e. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; f. Projected earnings sharing for the current year and report on true-up to actual earnings sharing for the prior year; and g. Any proposals for funding of incremental resources in support of customer service and load growth initiatives. 3. Identification of any efficiency initiatives that the Companies have undertaken, or intend to undertake, that require a payback period extending beyond the PBR plan period and make recommendations to the Commission with respect to the treatment of such initiatives (see Section 2.3.2 for a more detailed discussion of the ECM). 4. Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the Commission for decision as to their exclusion from the PBR plan. The review process should include recommendations as to how the exogenous events costs/revenues should be recovered from or credited to ratepayers (see Section 2.2.4 for details). 5. Review of the Companies' performance with respect to SQI's. Bring forward recommendations to the Commission where there have been a "sustained serious degradation" of service (see Section 2.3.3.2 for details). 6. Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews. For example, stakeholders are to review the usefulness of continuing with the Billing Index and Meter Reading Accuracy SQIs. 7. Assess and make recommendations to the Commission on the scope for future Annual Reviews.	185
82.	Fortis' request for a Mid-Term Review is denied.	186

83.	The Commission Panel directs, in the first Annual Review, in addition to the items previously set out, a consultation process to determine the performance range for SQIs be undertaken.	186
84.	The Commission Panel approves the RSAM rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23 and a of a credit of $0.120/GJ, effective January 1, 2014.	188
85.	The Commission Panel does not approve the establishment of an Industrial RSAM	190
86.	The Commission Panel approves the 2014 Residential Demand forecast.	191
87.	The Commission Panel approves FEI's 2014 Commercial Demand forecast.	192
88.	The Commission Panel does not approve the FEI's 2014 Rate Schedule 22 demand forecast.	194
89.	The Commission Panel directs FEI to increase the 2014 Rate Schedule 22 demand forecast by 21 percent.	194
90.	The Commission Panel further directs FEI to develop a mechanism to adjust the Rate Schedule 22 demand forecast methodology to better reflect the impact of falling gas prices, for review at the 2015 Annual Review.	194
91.	The Commission Panel approves FEI's 2014 NGT Demand forecast.	195
92.	Accordingly, the Commission Panel directs FEI to reduce the ES&ER Opening Base amount by $1.034 million.	210
93.	The Commission Panel therefore directs FEI to further reduce the Base O&M for the LTRP by $600,000.	210
94.	The Commission Panel directs contributions to political parties to be solely on the account of the shareholder.	211
95.	The Commission Panel directs that costs associated with the equivalent of one FTE in the ES&ER group be removed from the 2013 Base Year O&M. The Commission Panel directs FEI to include in the Compliance Filing a detailed breakout of the costs, including the labour component, that are included in the total of $410,000 of actual Biomethane Program O&M incurred in 2013 and therefore, removed from the 2013 Base Year and a detailed breakdown of the total of $570,000 of forecast Biomethane O&M costs that are transferred to the Biomethane Variance Account for the 2014 year.	212

96.	"The Commission Panel finds that 30 percent of the STIP costs are on the account of the shareholder. Therefore, the Panel directs FBC to recover only 70 percent of the STIP from the ratepayer and must reduce its O&M Base accordingly… Therefore, the Commission Panel finds that the STI costs as they relate to the ratepayer are to be restricted to the target (as outlined in the Hay Report) STI compensation only. The Panel understands that this equates to the target median within its comparative peer group and directs any amounts in excess of the target median to be borne by the shareholder… In summary, FBC is to calculate the STIP payment based on the target median and then deduct 30 percent of this calculation to arrive at the amount to be borne by the ratepayer…" (FBC 2014-2018 RRA Decision, Section 3.1.2.3) As part of its Compliance Filing, FEI is directed to provide the following information for 2013: (i) the amounts spent on the Executive STI, and (ii) the amount which would have been spent if only the target STI had been met (as per Page 9 of the Executive Compensation Benchmarking, Exhibit B-1-1, Appendix C-2). The difference between these two amounts must be deducted from the Base O&M.	212
97.	The Panel approves FEI's proposed 2013 Base Capital, for use in determining formulaic 2014 capital, as applied for, subject to any further change directed in this Decision.	215
98.	The Commission Panel approves FEI's request to discontinue the US GAAP to Canadian GAAP reconciliation in future BCUC Annual Reports.	217
99.	The Panel directs FEI to communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period.	217
100.	The Commission Panel approves FEI's request to include the retiree portion of pension and OPEB expenses in benefit loadings for O&M and Capital.	218
101.	The Commission Panel denies FEI's request to capitalize annual software upgrade costs. The Panel directs FEI to adjust its 2013 Base O&M and Capital to add the $1.8 million in annual software upgrade costs back to 2013 Base O&M and to remove this amount from 2013 Base Capital.	220

102.	The Commission Panel approves FEI's request to switch from its current vehicle leasing program to transition to a purchased vehicle fleet. The Commission Panel further approves a depreciation rate of 12.5 percent for asset class 484 Vehicles.	221
103.	The Commission Panel directs FEI to reduce its capitalized overhead rate to 12 percent.	223
104.	The Commission Panel approves FEI's request to modify the Lead/Lag days for cash working capital as outlined in the Application.	223
105.	The Panel approves FEI's request to change its method of calculating depreciation expense whereby depreciation expense commences at the beginning of the year following when the asset is placed into service.	225
106.	The Panel approves the allocation of shared services costs between FEI and FEVI and the allocation of shared services costs between FEI and FEW as outlined in the Application.	227
107.	FEI's request to allocate executive cross charges between FEI and FBC using the Massachusetts Formula is approved.	229
108.	The Commission Panel directs any changes to executive cross-charges resulting from the Code of Conduct/Transfer Pricing Policy proceeding be reflected as an adjustment to the Base O&M.	229
109.	The Panel approves the allocation of corporate services costs between FHI and FEI, as reflected in the Corporate Services Agreements between FHI and FEI and as outlined in the Application.	230
110.	The Commission Panel approves the establishment of the 2014–2018 PBR Application Costs deferral account as applied for by FEI and the amortization of this deferral account over the approved PBR period, which is six years, commencing January 1, 2014.	231
111.	The Commission Panel approves the establishment of the TESDA Overhead Allocation Variance deferral account. The Panel directs that the ending balance at December 31 each year be amortized over the following year.	232
112.	The Panel directs that the overhead allocation, along with any other TES related amounts that would otherwise be recorded in the TESDA, be recovered directly from FAES.	232
113.	The Commission Panel approves FEI's request to change the amortization period from three years to two years for the MCRA and RSAM deferral accounts as well as for the MCRA and RSAM Interest deferral accounts.	234

114.	The Commission Panel also directs FEI to reduce the amortization period for the SCP Mitigation Revenues Variance deferral account from the currently approved three years to two years so as to create alignment with the other margin-related deferral accounts.	234
115.	The Commission Panel denies FEI's request to change the Pension & OPEB Variance deferral account amortization period from three years to the EARSL. The Panel directs FEI to continue amortizing this deferral account over three years.	236
116.	The Commission Panel approves the requested five-year amortization period for the Customer Service Variance deferral account.	236
117.	In accordance with the directives in Section 3.2.7 of the Decision, the Panel approves the amortization of the balance in the Depreciation Variance deferral account over one year commencing January 1, 2014.	237
118.	The Panel denies FEI's request to capture these application costs in the existing Biomethane Program Costs deferral account.	238
119.	FEI is instead directed to record these costs in the Biomethane Variance Account.	238
120.	The Commission Panel approves the establishment of a rate base deferral account for the GCOC Stage 1 Application Costs. The Panel also approves the amortization of the balance of this account over two years beginning January 1, 2014.	239
121.	The Commission Panel approves the transfer of FEI's portion of the balance of the Amalgamation and Rate Design Application Costs, including the Reconsideration costs, which are currently being held in a non-rate base deferral account, to rate base beginning January 1, 2014. The Panel also approves the amortization of the balance of this rate base deferral account over three years commencing January 1, 2014.	240
122.	The Commission Panel grants approval to FEI to combine the residual balances in Rate Riders 3, 4 and 8 into the Residual Delivery Rate Riders Deferral Account and to amortize the balance into rates in 2014. The Panel also approves the transfer any remaining balance in Rate Rider 4 which exists in 2014 to the Residual Delivery Rate Riders Deferral Account for amortization into rates in 2015.	241
123.	The Panel approves FEI's request to transfer the ending 2014 balance in the non-rate base OBF Pilot Program deferral account to rate base on January 1, 2015. The Panel directs the balance to be recovered from OBF pilot program customers over a 10-year amortization period or until the balance has been fully recovered. T	242

124.	The Commission Panel finds that unused deferral accounts should be discontinued and approves FEI's request to discontinue the deferral accounts listed in Table 3.16 above as outlined in the Application and in subsequent Evidentiary Updates.	244
125.	Accordingly, the Panel directs FEI to discontinue use of the Gains and Losses deferral account, effective January 1, 2014.	246
126.	Therefore, the Panel directs FEI to amortize the December 31, 2013 balance in the Gains and Losses deferral account over 10 years beginning January 1, 2014.	246
127.	Therefore, the Commission Panel directs FEU to fully adopt the USoA and commence tracking all costs under the USoA as of the beginning of 2016. The Panel further directs FEI to file, for approval, by no later than March 31, 2015, a plan describing how it will implement this change.	248
128.	The Commission Panel directs FEI to include non-rate base deferral accounts and gas plant excluded from rate base in its financial schedules for the first Annual Review.	249
129.	Where appropriate, the Panel may consider the UCT as a checkpoint in evaluating EEC programs requiring the mTRC, along with other considerations including the ability of customers to participate in EEC programs.	260
130.	In evaluating the reasonableness of allocation of EEC funding between EEC programs that pass the TRC/mTRC, the Commission Panel determines that the UCT result is a relevant consideration.	260
131.	The Commission Panel determines that rate impacts are relevant when considering the interests of persons in British Columbia who receive or may receive service from FEU. However, the focus of this consideration should be on mitigating rate impacts for non-participants, and not on maintaining the competitive position of natural gas.	261
132.	The Commission Panel finds it appropriate to assess rate impact considerations only at the portfolio level, and not at the individual program level.	262
133.	The Commission Panel also determines that FEU should not use the Commission's FEU 2012–2013 EEC approval as a guide to the upper level of rate impacts that are appropriate for the programs FEU is proposing.	262
134.	The Commission Panel accepts FEU's calculation of the cost of gas for the mTRC. However, the Panel directs FEU to include an update of the avoided cost of gas used for the mTRC in the next EEC Annual Report.	263

135.	The Commission Panel accepts the calculation of the cost of energy for the TRC for the purpose of this Application.	263
136.	The Commission Panel directs FEU to provide an estimate of the effect of each of its simplifying assumptions on the avoided cost of gas used for the TRC in the next EEC Expenditure Request.	263
137.	The Commission Panel therefore approves FEU's request for endorsement of the recognition of spillover effects on a case-by-case basis where evaluation shows that spillover is occurring. Given the lack of an evidentiary basis for the 15 percent spillover rate proposed for the Residential Energy Efficient Home Performance Program, the Panel declines to accept any spillover effect for this program at this time.	264
138.	The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the New Technologies Program.	267
139.	Accordingly, the Commission Panel accepts FEU's proposed Residential EEC Program portfolio.	268
140.	The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the low income space heating top-up, water heating top-up and the non-profit custom programs. The funding request appears reasonable and has the support of BCSEA.	269
141.	The Commission Panel accepts FEU's proposed Low Income EEC Program portfolio.	270
142.	The Commission Panel accepts, subject to the condition laid out below, FEU's request for funding for the both the new Mechanical Insulation Pilot program and the new Specialized Industrial Process Technology Program.	271
143.	The Commission Panel accepts FEU's proposed Commercial EEC Program portfolio.	271
144.	The Commission Panel accepts FEU's proposed Industrial EEC Program portfolio.	272

145.	Accordingly, the Commission Panel accepts FEU's Innovative Technologies EEC Program portfolio. The Commission Panel accepts the Conservation Education and Outreach and the Enabling Activities EEC programs. To aid transparency, FEU are directed to allocate 'FEU labour costs coded to EEC' to its EEC programs, with the exception of costs related to Evaluation, Measurement & Verification which should be shown separately. FEU should include in the next EEC Annual Report a description of the cost allocation methodology used, and any differences between the methodology proposed and that used in the 2012–2013 Application.	272
146.	FEU are directed in the next EEC Annual Report to explain how it ensures the focus of the contractor network program is on reducing overall gas consumption by customers.	274
147.	The Commission Panel does not support FEU's argument that having generic EEC programs that renters can access meets the requirements of the DSM Regulations.	274
148.	The Commission Panel therefore directs FEU to, by the end of 2015 and within the existing EEC funding envelope, file with the Commission one or more EEC programs intended specifically to address the unique market barriers to energy efficiency faced by renters (for example, the landlord tenant split-incentive).	275
149.	The Commission Panel approves FEU's request for a five-year expenditure period.	275
150.	The Commission Panel approves FEU's EEC expenditure of $34.353 million for 2014; $36.537 for 2015; $35.839 for 2016; $35.388 for 2017 and $35.874 for 2018.	277
151.	The Commission Panel approves FEU's request that program funding transfer rules follow the same process approved by the Commission for the 2012–2013 test period. However, the Panel denies FEU's request to transfer funds to new programs not yet identified without pre-approval by the Commission.	278
152.	The Commission Panel directs FEU to include in the next FEU EEC Application an analysis of the rate impact of a reduction in the EEC amortization period to eight years and to five years. The Commission Panel approves FEU's request to (i) continue the EEC accounting treatment approved for 2012–2013 and (ii) to transfer any new amounts accumulated in the non-rate base EEC deferral account to FEU rate base EEC deferral account in the following year.	280

153.	The Commission Panel approves the third-party administration portion of the PWC proposal put forward by FEU.	283
154.	However, the Panel does not approve the initial and subsequent annual backward-looking review portion of the PWC proposal.	284
155.	The Commission Panel denies FEU's request to place the actual expenditures from PWC's administration of EEC funds for projects with a thermal energy component in the EEC non-rate base deferral account that attracts AFUDC.	284

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September 2014.

Original signed by:

____

D.M. MORTON
PANEL CHAIR/COMMISSIONER

Original signed by:

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D.A. COTE
COMMISSIONER

Original signed by:

____

N.E. MACMURCHY
COMMISSIONER

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

and

Application by FortisBC Energy Inc.
for Approval of a Multi-Year Performance Based Ratemaking Plan
for the years 2014 through 2018

BEFORE: D.M. Morton, Panel Chair/Commissioner
D.A. Cote, Commissioner
N.E. MacMurchy, Commissioner

September 15, 2014

O R D E R

WHEREAS:

A. On June 10, 2013, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission (Commission) for approval of a proposed multi-year Performance Based Ratemaking (PBR) plan for the years 2014 through 2018, and for approval of a permanent natural gas delivery rate increase of approximately 0.7 percent as compared to 2013 permanent delivery rates effective January 1, 2014, pursuant to sections 59 to 61 of the *Utilities Commission Act* (Act) (Application);

B. FEI seeks, among other things, approvals relating to:

- Allocation of costs for corporate and shared services;
- Discontinuation, continuation and creation of deferral accounts and the amortization and disposition of balances in deferral accounts;
- A Rate Stabilization Adjustment Mechanism rider for applicable rate classes for 2014 as set out in the Application;

C. FEI, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (together, the FortisBC Energy Utilities) seek acceptance of Energy Efficiency and Conservation expenditures pursuant to section 44.2 of the Act;

D. On July 16, 2013, FEI filed an Evidentiary Update (Exhibit B-1-3), on September 6, 2013, FEI filed a second Evidentiary Update (Exhibit B-15), and on February 21, 2014, FEI filed a third Evidentiary Update (Exhibit B-1-5). In Exhibit B-1-5, FEI requests for approval of a permanent natural gas delivery rate increase of approximately 0.6 percent as compared to 2013 permanent delivery rates effective January 1, 2014;

E. By Order G-99-13 on June 21,2013, the Commission established a Preliminary Regulatory Timetable for review of the FEI Application that included two rounds of Information Requests (IRs)and a Procedural Conference;

F. On September 5, 2013, a Procedural Conference was held jointly with FEI's affiliate, FortisBC Inc. (FBC), who has also applied for approval of a PBR plan by the Commission. The Procedural Conference considered the regulatory process for both the FEI and FBC applications and the possibility of combining some parts or all of the two proceedings;

G. By Order G-150-13, the Commission amended the Regulatory Timetables and established an Oral Hearing to review PBR related issues be held jointly with FBC. The Commission also approved a 0.7 percent rate increase on interim and refundable basis for FEI, effective January 1, 2014;

H. The Regulatory Timetable for review of the Application was further amended by Orders G-164-13, G-205-13, G-218-13, G-7-14, and G-9-14;

I. The Oral Hearing on PBR issues commenced on March 10, 2014 and was completed on March 18, 2014;

J. Between April 25, 2014 and May 22, 2014, FEI and Interveners filed their Final Submissions on both the PBR and Non PBR issues. On June 12, 2014, FEI filed its Reply Submissions on PBR and Non PBR issues.

K. On June 19, 2014, the Commission Panel issued Panel IR No. 1 and an Oral Argument Regulatory Timetable for the Panel IRs, related responses, and the Panel's additional topics to be addressed in Oral Argument;

L. On July 14, 2014, the Commission Panel held the Oral Argument Phase to address Panel IRs, related responses, and the Panel's additional topics;

M. The Commission has considered the FEI Application, the evidence and submissions by all parties in this proceeding and provides its Reasons for Decision issued concurrently with this Order.

NOW THEREFORE the Commission, for the reasons stated in the Decision, orders as follows:

1. Pursuant to sections 59 to 61 of the *Utilities* Commission *Act*:

   a) An amended Performance Based Ratemaking mechanism for setting rates for period 2014 to 2019 is approved.

   b) An increase of 0.6 percent compared to 2013 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2013 levels is not approved.

c) A Rate Stabilization Adjustment Mechanism rider credit amount of $0.120/GJ for customers served under FortisBC Energy Inc. (FEI) Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23, effective January 1, 2014, as set out in Section E Schedule 63 of the Application is approved.

d) Discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, as modified by the Decision, are approved.

e) Changes to the accounting policies to be used in the determination of rates for FEI as set out in the Application, as modified by the Decision, are approved, effective January 1, 2014.

f) Continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2014-2018 PBR Period as set out in Section C2.3 of the Application is approved.

g) Allocation of costs for corporate services between FortisBC Holdings Inc. and FEI and for Shared Services as between FEI and FortisBC Energy (Vancouver Island) Inc., and between FEI and FortisBC Energy (Whistler) Inc. (FEW), as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Section D3.6 of the Application is approved.

2. Pursuant to section 44.2 of the *Utilities Commission Act*, Energy Efficiency and Conservation (EEC) expenditures (excluding inflation) of $34.353 million in 2014, $36.537 million in 2015, $35.839 million in 2016, $35.388 million and in 2017 and $35.874 million in 2018.

3. FEI is directed to resubmit its financial schedules incorporating all the adjustments as outlined in the Decision, within 60 days of this Order.

4. The Commission will accept, subject to timely filing, amended Tariff Rate Schedules which conform to the Decision.

5. FEI is to provide notice of the rate change to customers via a bill message, to be reviewed in advance by Commission staff to confirm compliance with this Order.

6. FEI must comply with all other directives contained in the Decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 15th day of September of 2014.

BY ORDER

Original signed by:

D.M. Morton
Commissioner/Panel Chair

Glossary

2013 Biomethane Decision	Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis
AES	Alternative Energy Solutions
AFUDC	Allowance for Funds Used During Construction
AIFR	All Injury Frequency Rate
AMI	Advanced Metering Infrastructure
Application	Multi-Year Performance Based Ratemaking Plan for the Years 2014 through 2018 Including Approval of Rates for 2014 in Accordance with the PBR Plan
ARM	Attrition Relief Mechanism
AUC	Alberta Utilities Commission
B&V	Black and Veatch
BC Hydro	British Columbia Hydro and Power Authority
BC-AWE	BC All Weekly Earnings
BC-CPI	British Columbia Consumer Price Index
BCPSO	British Columbia Pensioners' and Seniors' Organization
BCSEA	BC Sustainable Energy Association and the Sierra Club of British Columbia
Capex	Capital Expenditures
CCE	Customer Care Enhancement
CEA	Clean Energy Act
CEC	Commercial Energy Consumers of British Columbia

CEO	Conservation, Education and Outreach
CGA	Canadian Gas Association
CIS	Customer Information System
CNG	Compressed Natural Gas
COC	Coalition for Open Competition
CoC/TPP	Code of Conduct/Transfer Pricing Policy
Commission	British Columbia Utilities Commission
COPE	Canadian Office and Professional Employees Union Local 378
COS	Cost of Service
CPCN	Certificate of Public Convenience and Necessity
CPI	Consumer Price Index
CRP	Conservation Potential Review
CSPI	Commercial Software Price Index
DSM	Demand-Side Management
DSM Regulation	Demand-Side Measures Regulation
EARSL	Expected Average Remaining Service Life
ECAP	Energy Conservation and Assistance Program
ECI	Employment Cost Index
ECM	Efficiency Carry-Over Mechanism
EEC	Energy Efficiency and Conservation
EM&V	Evaluation, Measurement & Verification
ES&ER	Energy Solutions & External Relations
ES&RD	Energy Supply & Resource Development

ESM	Earnings Sharing Mechanism
EUCPI	Electric Utility Construction Price Index
FAES	FortisBC Alternative Energy Services Inc.
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.
FERC	Federal Energy Regulatory Commission
FEU	FortisBC Energy Utilities (FEI, FEVI, FEW)
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FHI	FortisBC Holdings Inc.
FI	Fortis Inc.
Fortis	FEI and FBC
FTE	Full Time Equivalent
GAAP	Generally Accepted Accounting Principles
GCOC	Generic Cost of Capital Application Costs
GGRR	Greenhouse Gas Reductions Regulation
GJ	Gigajoule
GST	Goods and Services Tax
HST	Harmonized Sales Tax
ICG	Industrial Consumers Group
IFRS	International Financial Reporting Standards
IRG	Irrigation Ratepayers Group
IRP	Integrated Resource Plan

IRs	Information Requests
ISP	Integrated System Plan
IT	Information Technology
KORP	Kingsvale-Oliver Reinforcement Project
LNG	Liquefied Natural Gas
LRMC	Long-Run Marginal Cost
LTRP	Long Term Resource Plan
M&S	Materials and Services
M&V	Measurement and Verification
MCRA	Midstream Cost Reconciliation Account
MEM	BC Ministry of Energy and Mines
MFP	Multifactor Productivity
MFP^N	Multifactor Productivity Index
mTRC	modified Total Resource Test
NERA	National Economic Research Associates
NGT	Natural Gas for Transportation
NSA	Negotiated Settlement Agreement
NSP	Negotiated Settlement Process
O&M	Operating and Maintenance
OBF	On-Bill Financing
OEB	Ontario Energy Board
OPEB	Other Post-Employment Benefits
Opex	Operating & Maintenance Expenditure

PBR	Performance Based Ratemaking
PBR Plan	Performance Based Ratemaking for the years 2014 through 2018
PEG	Pacific Economic Group
PST	Provincial Sales Tax in British Columbia
PWC	Price Waterhouse Coopers
RIM	Rate Impact Measure
RNG	Renewable Natural Gas
ROE	Return on Equity
RRA	Revenue Requirements Application
RSAM	Rate Stabilization Adjustment Mechanism
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCP	Southern Crossing Pipeline
SQI	Service Quality Indicator
STIP	Short Term Incentive Plan
TES	Thermal Energy Services
TESDA	Thermal Energy Services Deferral Account
TFP	Total Factor Productivity
TGI	Terasen Gas Inc.
TRC	Total Resource Cost
UCA	Utilities Commission Act
UCT	Utility Cost Test
UPC	Use Per Customer

USoA	Uniform System of Accounts
WACC	Weighted Average Cost of Capital

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

and

FortisBC Energy Inc.
Application for Approval of a Multi-Year Performance Based Ratemaking Plan
for 2014 through 2018

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter Dated June 17, 2013 - Appointing the Commission Panel for the review of the FortisBC Energy Inc. Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018
A-2	Letter Dated June 21, 2013 – Commission Order G-99-13 establishing a Preliminary Regulatory Timetable and Procedural Conference
A-3	Letter Dated July 23, 2013 – Commission Information Request No. 1 to FEI
A-4	**CONFIDENTIAL** Letter dated July 23, 2013 – Confidential Commission Information Request No. 1 to FEI
A-5	Letter Dated August 23, 2013 – BCUC Requesting Justification on COPE 378's Late Supplemental Information Request
A-6	Letter Dated August 29, 2013 – BCUC informing that the Procedural Conference will be a joint conference with registered participants of FortisBC Inc.'s Performance Based Ratemaking Revenue Requirements 2014 – 2018 Application
A-7	Letter Dated August 30, 2013 – BCUC issuing Procedural Conference Items
A-8	Letter Dated September 10, 2013 – Appointment of Commissioner Magnan
A-9	Letter Dated September 13, 2013 – Order G-150-13, amending the Regulatory Timetable

A-10	Letter Dated October 4, 2013 – Order G-164-13 Amending the Regulatory Timetable
A-11	Letter Dated October 25, 2013 – Commission Information Request No. 2 to FEI on all non-PBR methodology issues
A-12	**CONFIDENTIAL** - Letter Dated October 25, 2013 – Confidential Commission Information Request No. 2 to FEI on all non-PBR methodology issues
A-13	Letter Dated November 8, 2013 – Commission Information Request No. 2 to FEI on PBR methodology
A-14	Letter Dated December 2, 2013 – Order G-205-13 Amending the Regulatory Timetable
A-15	Letter L-73-13 Dated December 12, 2013 – BCUC Response to COPE letter
A-16	Letter Dated December 18, 2013 – Order G-218-13 Amending the Regulatory Timetable
A-17	Letter L-74-13 December 18, 2013 – EEC Funding Request for Comments
A-18	Letter dated December 30, 2013 – Commission Order G-230-13 - Acceptance of EEC Expenditure Schedule
A-19	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCPSO on Intervener Evidence
A-20	Letter Dated January 16, 2014 – Commission Information Request No. 1 to COPE 378 on Intervener Evidence
A-21	Letter Dated January 16, 2014 – Commission Information Request No. 1 to CEC on Intervener Evidence
A-22	Letter Dated January 16, 2014 – Commission Information Request No. 1 to BCSEA on Intervener Evidence
A-23	Letter Dated January 16, 2014 – Commission Order G-7-14 Amending the Regulatory Timetable
A-24	Letter L-3-14 dated January 16, 2014 - Scope of Oral Hearing

A-25	Letter Dated January 23, 2014 – Commission Order G-9-14 Amending the Regulatory Timetable
A-26	Letter Dated February 12, 2014 – Commission Information Request No. 2 to BCPSO on Intervener Evidence
A-27	Letter Dated February 12, 2014 – Commission Information Request No. 2 to CEC on Intervener Evidence
A-28	Letter Dated February 12, 2014 – Commission Information Request No. 2 to BCSEA on Intervener Evidence
A-29	Letter Dated February 19, 2014 – Oral Hearing Information
A-30	Letter Dated February 28, 2014 – CEC IR Response - Request for Submission
A-31	Letter Dated March 4, 2014 – Panel's decision on certain CEC's IR responses
A-32	Letter Dated March 18, 2014 – Final Submissions Regulatory Timetable
A-33	Letter Dated March 27, 2014 – Commission Information Request No. 1 to FEI on Rebuttal Evidence
A-34	Letter Dated April 30, 2014 – Request for comments on CEC's Request for an Extension of the Deadline for Filing of Argument by Interveners
A-35	Letter Dated April 30, 2014 – Recusal of Commissioner Magnan
A-36	Letter Dated May 8, 2014 – Response to CEC Request for Extension
A-37	Letter Dated June 19, 2014 – Panel Information Request No. 1, Oral Argument and Regulatory Timetable
A-38	Letter Dated June 27, 2014 – Commission Submitting Oral Argument Topics
A-39	Letter Dated July 10, 2014 – Commission Submitting Oral Argument Clarification

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated July 23, 2013 – Commission Staff filing Aligning Utility Incentives with Investment in Energy Efficiency, A resource of the National Action Plan for Energy Efficiency, November 2007
A2-2	Letter dated July 23, 2013 – Commission Staff filing Energy Provider-Delivered Energy Efficiency International Energy Agency, 2013
A2-3	Letter dated July 23, 2013 – Commission Staff filing FortisBC Energy Inc. Clarification of Commission Letter L-33-13
A2-4	Letter dated July 23, 2013 – Commission Staff filing Letter L-32-13-Compliance Filings of the 2012 FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. Main Extension and FEI Vertical Subdivision Reports
A2-5	Letter dated July 23, 2013 – Commission Staff filing Excerpts from FEI's Annual Contracting Plans
A2-6	Letter dated July 23, 2013 – Commission Staff filing Compliance Filing FortisBC Energy Inc. the Tilbury Property Purchase CPCN
A2-7	Letter dated July 23, 2013 – Commission Staff Filing Excerpt from FEI and FEVI 2012 Main Extension Report
A2-8	Letter dated July 23, 2013 – Commission Staff Filing FortisBC Holding Inc. Statement of Executive Compensation for 2012
A2-9	Letter dated September 4, 2013 – Commission Staff Submissions for the September 5, 2013 Procedural Conference
A2-10	Letter date October 23, 2013 – Commission Staff filing June 2013 LGMA Exchange
A2-11	Letter date October 23, 2013 – Commission Staff filing Natural Gas Vehicle Infrastructure Canada Brochure
A2-12	Letter date October 23, 2013 – Commission Staff filing Excerpt from Terasen Gas Inc. 2010-2011 Application – Response to BCUC IR No. 1
A2-13	Letter date October 23, 2013 – Commission Staff filing FEU-Uniform System of Accounts Report

A2-14 Letter date October 23, 2013 – Commission Staff filing Commission letter dated December 3, 2012 – Compliance Filing FortisBC Energy Inc. – BCUC Uniform System of Accounts Report

A2-15 Letter date October 23, 2013 – Commission Staff filing FortisBC Energy Utilities - Uniform System of Accounts Report – Response to Information Request No. 1

A2-16 Letter date October 23, 2013 – Commission Staff filing Article from IT Business Canada – Habanero-Consulting Group

A2-17 Letter date October 23, 2013 – Commission Staff filing Excerpt from 2012 Annual Report of FortisBC Energy Inc

A2-18 Letter date November 8, 2013 – Commission Staff filing Business Council of British Columbia – Productivity: BC's Position and Why We Should Care

A2-19 Letter date November 8, 2013 – Commission Staff filing Special Report – TD Economics – Estimating Longer-Term Growth Prospects in Canada's Provincial Economies

A2-20 Letter date November 8, 2013 – Commission Staff filing Excerpt from Ontario Energy Board Staff Report to the Board on Performance Measurement and Continuous Improvement for Electricity Distributors

A2-21 Letter date November 8, 2013 – Commission Staff filing Report from the 9th International Conference on Probabilistic Methods Applied to Power Systems — Utilizing Bulk Electric System Reliability Performance Index Probability Distributions in a Performance Based Regulation Framework

A2-22 Submitted at Oral Hearing March 12, 2014 – FortisBC and FortisBC Energy Inc. 2014-2018 Performance Based Rates – Staff Witness Aids

A2-23 Submitted at Oral Hearing March 12, 2014 – FortisBC/FEI 2014-2018 PBR Witness Aid - Inflation

A2-24 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PNR Witness Aid – St. Additions

A2-25 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FBC Scenario 1

A2-26 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – Capital, FEI Scenario 1

A2-27 Submitted at Oral Hearing March 13, 2014 – FBC/FEI 2014-2018 PBR Staff Witness Aid – ECM, with Cover Page Re. Scenarios 1 &2

A2-28 Submitted at Oral Hearing March 13, 2014 – Extract from Decision of Ontario Energy Board in the Matter of an Application by Enbridge Gas Distribution

A2-29 Submitted at Oral Hearing March 14, 2014 - FBC/FEI 2014-2018 PBR Staff Witness Aid - COPE

A2-30 Submitted at Oral Hearing March 17, 2014 – Response to BCUC Information Request No. 1, page 161, Submission Date September 20, 2013

APPLICANT DOCUMENTS

B-1 **FORTISBC ENERGY INC. (FEI)** Letter Dated June 10, 2013 - Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 Volume 1

B-1-1 Letter Dated June 10, 2013 – FEI Submitting Application Appendices Volume 2

B-1-2 **CONFIDENTIAL** Letter Dated June 10, 2013 - FEI Submitting Confidential Page 127

B-1-3 Letter Dated July 16, 2013 – FEI Submitting Evidentiary Update to Application

B-1-4 Letter Dated December 13, 2013 – FEI Submitting Erratum to the Application Appendix D2

B-1-5 Letter Dated February 21, 2014 – FEI Submitting Evidentiary Update to Application

B-2 Letter Dated June 20, 2013 - FEI Submitting EEC and Demand Forecast May 15, 2013, Workshop Materials

B-3 Letter Dated June 20, 2013 - FEI Submitting June 19, 2013 PBR Workshop Materials

B-4 **CONFIDENTIAL** Letter Dated June 28, 2013 - FEI Submitting Confidential Forecasting Model

B-5 Letter Dated July 2, 2013 - FEI Submitting Application Tables

B-6	Letter Dated August 23, 2013 – FEI Submitting Responses to BCPSO Information Request No. 1
B-7	Letter Dated August 23, 2013 – FEI Submitting Responses to BCSEA Information Request No. 1
B-7-1	**CONFIDENTIAL** - Letter Dated August 23, 2013 – FEI Submitting Confidential Responses to BCSEA Information Request No. 1
B-8	Letter Dated August 23, 2013 – FEI Submitting Responses to CEC Information Request No. 1
B-8-1	**CONFIDENTIAL** - Letter Dated August 23, 2013 – FEI Submitting Confidential Responses to CEC Information Request No. 1
B-9	Letter Dated August 23, 2013 – FEI Submitting Responses to COPE Information Request No. 1
B-9-1	**CONFIDENTIAL** - Letter Dated August 23, 2013 – FEI Submitting Confidential Responses to COPE Information Request No. 1
B-10	Letter Dated August 23, 2013 – FEI Submitting Responses to COPE Supplemental Information Request No. 1
B-11	Letter Dated August 23, 2013 – FEI Submitting Responses to BCUC Information Request No. 1
B-11-1	Letter Dated August 23, 2013 – FEI Submitting Attachments for Responses to BCUC Information Request No. 1
B-11-1-1	Letter Dated September 3, 2013 - FEI Submitting Attachment 140.3
B-11-2	**CONFIDENTIAL** Letter Dated August 23, 2013 – FEI Submitting Confidential Responses to BCUC Information Request No. 1
B-11-3	**CONFIDENTIAL** Letter Dated August 23, 2013 – FEI Submitting Confidential Responses to BCUC Information Request No. 1.172.4 and 1.236.3 and Attachments
B-12	Letter Dated August 22, 2013 – FEI Submitting Response to COPE Request to File Supplemental Information Request
B-13	Letter Dated August 23, 2013 – FEI Submitting Responses to COC Information Request No. 1

B-14	Letter Dated September 4, 2013 - FEI Submissions for the September 5, 2013 Procedural Conference
B-15	Letter dated September 6, 2013 – FEI Submitting Evidentiary Update
B-16	Letter dated September 20, 2013 – FEI-FBC Joint Procedural Conference Response to Undertaking
B-17	Letter dated September 24, 2013 – FEI-FBC Response to COPE Request to Amend Timetable
B-18	Letter Dated November 22, 2013 – FEI Notice of Delay filing responses to BCUC IR No. 2 BCUC Confidential IR No. 2 and CEC IR No. 2
B-19	Letter Dated November 22, 2013 – FEI Response to COC IR No. 2
B-19-1	**CONFIDENTIAL** Letter Dated November 22, 2013 – FEI Response to COC IR No. 2 Confidential Attachment 8.1
B-20	Letter Dated November 22, 2013 – FEI Response to BCSEA IR No. 2
B-20-1	**CONFIDENTIAL** Letter Dated November 22, 2013 – FEI Response to BCSEA IR No. 2 Confidential Attachment 1.5.3
B-21	Letter Dated November 22, 2013 – FEI Response to BCPSO IR No. 2
B-22	**CONFIDENTIAL** Letter Dated November 26, 2013 – FEI Response to BCUC Confidential IR No. 2
B-23	Letter Dated November 26, 2013 – FEI Response to CEC IR No. 2
B-23-1	Letter Dated December 13, 2013 - FEI Response to CEC IR2 Errata to 2.89.1
B-24	Letter Dated November 27, 2013 – FEI Response to BCUC IR No. 2
B-24-1	**CONFIDENTIAL** Letter Dated November 27, 2013 – FEI Confidential Attachments to Response to BCUC IR No. 2
B-24-2	Letter Dated December 13, 2013 - FEI Response to BCUC IR2 Errata to Attachment 376.1

B-25	Letter Dated November 28, 2013 – FEI Response to COC IR No. 2
B-26	Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR2a - Non PBR Methodology
B-27	Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR2a - Non PBR Methodology
B-28	Letter Dated December 6, 2013 - FEI-FBC Response to COPE IR2A - Non PBR Methodology
B-29	Letter Dated December 11, 2013 - FEI-FBC Response to COPE Letter
B-30	Letter Dated December 12, 2013 - FEI Request for Acceptance of EEC Expenditure Schedule for 2014
B-31	Letter Dated December 17, 2013 - FEI-FBC Response to Requests for Extensions to the Regulatory Timetable for Intervener Evidence
B-32	Letter Dated December 24, 2013 – FEI Reply Submission regarding EEC Funding
B-33	Letter Dated January 6, 2014 – FEI-FBC Rebuttal Evidence Confirmation
B-34	Letter Dated January 13, 2014 – FEI Submission on the Remainder of the Regulatory Timetable
B-35	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCPSO
B-36	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to BCSEA
B-37	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to CEC
B-38	Letter Dated January 16, 2014 – FEI-FBC Submitting Information Request No. 1 to COPE
B-39	Letter Dated February 12, 2014 – FEI-FBC Submitting IR No. 2 to CEC on Intervener Evidence

B-40	Letter Dated February 27, 2014 – FEI-FBC Submitting Objection to CEC IR Responses on Capital Tracker Mechanism
B-41	Letter Dated February 28, 2014 – FEI-FBC Submitting Witness Panels, Direct Testimony and Notice of Cross Examination
B-42	Letter Dated March 3, 2014 – FEI-FBC Submitting Reply regarding Request to Strike CEC IRs
B-43	Letter Dated March 3, 2014 – FEI-FBC Submitting EEC Evidentiary Amendment
B-43-1	**CONFIDENTIAL** Letter Dated March 3, 2014 – FEI-FBC Submitting EEC Evidentiary Amendment CONFIDENTIAL Attachment 1.1
B-44	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to BCPSO
B-45	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to CEC-COPE
B-46	Letter Dated March 3, 2014 – FEI Submitting Rebuttal Evidence to BCSEA
B-47	Letter Dated March 3, 2014 – FEI-FBC Submitting Rebuttal Evidence to COPE
B-48	Letter Dated March 7, 2014 – FEI-FBC Submitting Opening Statement Presentation
B-49	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Testimony of Dr. H. Edwin Overcast, Black & Veatch to CEC
B-49-1	Letter Dated March 10, 2014 – FEI-FBC Supplemental Rebuttal Evidence to CEC
B-50	Letter Dated April 11, 2014 - FEI Response to BCSEA IR No. 1 on FEI Rebuttal Evidence
B-51	Letter Dated April 11, 2014 - FEI Response to BCUC IR No. 1 on FEI Rebuttal Evidence
B-52	Letter Dated April 11, 2014 - FEI Response to CEC IR No. 1 on FEI Rebuttal Evidence
B-53	Letter Dated April 29, 2014 - FEI-FBC Submitting Objection to CEC Request for Extension

B-54	Letter Dated June 27, 2014 - FEI-FBC Responses to Panel Information Request No. 1
B-55	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Request for Procedural Confirmation
B-56	Letter Dated July 10, 2014 - FEI-FBC Oral Argument Procedural Confirmation Reply
B2-1	Letter Dated December 6, 2013 - FEI Response to BCUC IR3a - PBR Methodology
B2-2	Letter Dated December 6, 2013 - FEI Response to CEC IR3a - PBR Methodology
B2-3	Letter Dated December 6, 2013 - FBC Response to BCUC IR3a - PBR Methodology
B2-4	Letter Dated December 6, 2013 - FBC Response to BCPSO IR3a - PBR Methodology
B2-5	Letter Dated December 6, 2013 - FBC Response to BCSEA IR3a - PBR Methodology
B2-6	Letter Dated December 6, 2013 - FBC Response to CEC IR3a - PBR Methodology
B2-7	Letter Dated December 6, 2013 - FBC Response to ICG IR3a - PBR Methodology
B2-8	Letter Dated December 6, 2013 - FEI-FBC Response to BCUC IR3 – PBR Methodology
B2-9	Letter Dated December 6, 2013 - FEI-FBC Response to BCPSO IR3 – PBR Methodology
B2-10	Letter Dated December 6, 2013 -FEI-FBC Response to BCSEA IR3 – PBR Methodology
B2-11	Letter Dated December 6, 2013 -FEI-FBC Response to CEC IR3 – PBR Methodology
B2-12	Letter Dated December 6, 2013 -FEI-FBC Response to CEC Supplemental IR3 – PBR Methodology
B2-13	Letter Dated December 6, 2013 -FEI-FBC Response to COPE IR3 – PBR Methodology
B2-13-1	Letter Dated December 11 2013 - FEI-FBC Response to COPE Letter IR 3.G.14
B2-14	Letter Dated December 6, 2013 -FEI-FBC Response to ICG IR3 – PBR Methodology

B2-15 Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 1 re. Volume 2, Page 362, Line 6 to Page 264, Line 20

B2-16 Submitted at Oral Hearing March 12, 2014 – FortisBC Undertaking No. 2, re. Volume 2, Page 293, Line 25 to Page 296, Line 5

B2-17 Submitted at Oral Hearing March 12, 2014 –Empirical Research in Support of Incentive Rate Setting, 2012 Update Report to the Ontario Energy Board Dated September, 2013 by Pacific Economics Group Research

B2-18 Submitted at Oral Hearing March 13, 2014 – FortisBC Undertaking No. 3 re. Volume 2, Page 357, Line 5 to Page 358, Line 7

B2-19 Submitted at Oral Hearing March 13, 2014 – FEI Undertaking No. 4 re. Volume 3, Page 406, Line 20 to Page 407, Line 217

B2-20 Submitted at Oral Hearing March 14, 2014 – FEI Undertaking No. 5 re. Volume 4, Page 603, Lines 16 to 24

B2-21 Submitted at Oral Hearing March 14, 2014 – FEI Undertaking No. 6 re. Volume 4, Page 606, Lines 13 to 23

B2-22 Submitted at Oral Hearing March 14, 2014 – "FortisBC Materials for Cross-Examination of Ms. Barbara Alexander (COPE)"

B2-23 Submitted at Oral Hearing March 14, 2014 – FEI Undertaking No. 7 re. Volume 4, Page 607, Lines 4 to 14

B2-24 Submitted at Oral Hearing March 14, 2014 – FEI Undertaking No. 8 re. Volume 4, Page 822, Lines 5 to 16

B2-25 Submitted at Oral Hearing March 14, 2014 – FEI Undertaking No. 9 re. Volume 4, Page 674, Line 17 to Page 674, Line 14

B2-26 Submitted at Oral Hearing March 17, 2014 – Evidence of Russ Bell

B2-27 Submitted at Oral Hearing March 18, 2014 – FortisBC Materials for Cross-Examination of Dr. Mark Lowry (CEC)

B2-28 Submitted at Oral Hearing March 18, 2014 – FortisBC Undertaking No. 10 re. Volume 6, Page 1160, Lines 21 to 26

B2-29 Submitted at Oral Hearing March 18, 2014 – FortisBC Undertaking No. 11 re. Volume 6, Page 1162, Lines 5 to 14

B2-30 Submitted at Oral Hearing March 18, 2014 – FortisBC Undertaking No. 12 re. Volume 6, page 1249, Line 20 to Page 1250, Line 19

B2-31 Submitted at Oral Hearing March 18, 2014 - **CONFIDENTIAL** –"Cost Trends of Gas Utility Construction, Cost Trend Tables 1912 to July 1, 2013" from Handy-Whiteman

B2-32 Submitted at Oral Hearing March 18, 2014 – Excel Spreadsheet

B2-33 Submitted at Oral Hearing March 18, 2014 – FortisBC Undertaking No. 13 re. Volume 6, Page 1266, Lines 10 to 21

B2-34 Submitted at Oral Hearing March 18, 2014 – FortisBC Undertaking No. 14, re. Volume 6, Page 1269, Line 10 to Page 1271, Line 10

B2-35 Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 15,V6, p. 1210, SQI Incentive Payments

B2-36 Submitted March 19, 2014 – FEI-FBC Response to Undertaking No. 16, V4, p. 772 Scenarios

Intervenor Documents

C1-1 **Commercial Energy Consumers Association of British Columbia (CEC)** Letter dated June 20, 2013 – Request for Intervener Status by Christopher P. Weafer

C1-2 Letter Dated July 8, 2013 – CEC Submitting Undertaking of Confidentiality for Mr. Weafer

C1-3 Letter dated July 30, 2013 – CEC Submitting Information Request No. 1 to FEI

C1-4 Submitted at Hearing September 5, 2013 - Proposed Schedule

C1-5 Letter dated November 1, 2013 – CEC Submitting Information Request No. 2 Non-PBR

C1-6	Letter dated November 15, 2013 – CEC Submitting Information Request No. 2 on Performance Based Rates Methodology issues
C1-7	Letter dated November 18, 2013 – CEC Submitting Supplemental Information Requests
C1-8	Letter dated December 16, 2013 - CEC Submitting Filing Extension Request
C1-9	Letter Dated December 20, 2013 – CEC Submitting Evidence
C1-9-1	Letter Dated January 7, 2014 – CEC Submitting Errata to Evidence
C1-10	Letter Dated December 20, 2013 – CEC Submission on EEC Funds
C1-11	Letter Dated January 13, 2014 – CEC Submission on the Remainder of the Regulatory Timetable
C1-12	Letter Dated January 16, 2014 – CEC Submitting Information Request No. 1 to COPE
C1-13	Letter Dated January 29, 2014 – CEC Submitting Response to BCUC IR No. 1
C1-13-1	Letter Dated January 30, 2014 – CEC Submitting Further Response to BCUC IR No. 1
C1-14	Letter Dated January 29, 2014 – CEC Submitting Response to BCSEA IR No. 1
C1-14-1	Letter Dated January 31, 2014 – CEC Submitting Further Response to BCSEA IR No. 1
C1-15	Letter Dated January 29, 2014 – CEC Submitting Response to BCPSO IR No. 1
C1-15-1	Letter Dated January 31, 2014 – CEC Submitting Further Response to BCPSO IR No. 1
C1-16	Letter Dated January 29, 2014 – CEC Submitting Response to FEI FBC IR No. 1
C1-16-1	Letter Dated February 5, 2014 – CEC Submitting Further Responses to FEI FBC IR No. 1
C1-17	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to BCPSO on Intervener Evidence
C1-18	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to COPE on Intervener Evidence

C1-19	Letter Dated February 12, 2014 – CEC Submitting IR No. 2 to BCSEA on Intervener Evidence
C1-20	Letter Dated February 26, 2014 – CEC Submitting Response to BCPSO IR No. 2
C1-21	Letter Dated February 26, 2014 – CEC Submitting Response to BCSEA IR No. 2
C1-21-1	Letter Dated March 4, 2014 – CEC Submitting Update to BCSEA IR No. 2.16.1
C1-22	Letter Dated February 26, 2014 – CEC Submitting Response to BCUC IR No. 2
C1-22-1	Letter Dated March 4, 2014 – CEC Submitting Update to BCUC IR No.2.12.1
C1-23	Letter Dated February 26, 2014 – CEC Submitting Response to FEI FBC IR No. 2
C1-24	Letter Dated March 3, 2014 – CEC Submitting Witness Panel
C1-25	Letter Dated March 3, 2014 – CEC Submitting Comments regarding FEI-FBC Objection to CEC IR Responses
C1-26	Letter Dated March 28, 2014 – CEC Information Request to FEI on Rebuttal Evidence
C1-27	Letter Dated April 29, 2014 - CEC Extension Request
C1-28	Letter Dated June 27, 2014 - CEC Responses to Panel Information Request No. 1
C1-29	Letter Dated July 10, 2014 - CEC Submitting Comments regarding Oral Argument Phase
C2-1	**CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION, LOCAL 378 (COPE 378)** Letter dated June 24, 2013 – Request for Intervener Status by Jim Quail and Leigha Worth
C2-2	Letter dated July 30, 2013 – COPE Submitting Information Request No. 1 to FEI
C2-3	Letter dated August 14, 2013 - COPE Submitting supplementary Information Request
C2-4	WITHDRAWN - Letter dated August 22, 2013 – COPE Submitting Supplemental Information Request
C2-5	Letter dated August 26, 2013 – COPE Submitting Response regarding Supplemental Information Request

C2-6 Letter dated August 23, 2013 – COPE Submitting Information Regarding Consultant

C2-7 Letter dated September 20, 2013 – COPE 378 Submitting Application to Amend Regulatory Timetable

C2-8 Letter dated November 13, 2013 – COPE 378 Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C2-9 Letter dated December 10, 2013 – COPE 378 Submitting Responses to FEI (B2-13)-FBC (B-29) Information Request

C2-10 Letter dated December 17, 2013 - COPE 378 Submitting Evidence

C2-11 Letter dated December 18, 2013 - COPE 378 Submitting Comments regarding EEC Funding

C2-12 Letter Dated January 14, 2014 – COPE 378 Late Submission on the Remainder of the Regulatory Timetable

C2-13 Letter Dated January 29, 2014 – COPE Submitting Response to BCUC IR No. 1

C2-14 Letter Dated January 29, 2014 – COPE Submitting Response to FEI-FBC IR No. 1

C2-15 Letter Dated January 29, 2014 – COPE Submitting Response to BCSEA IR No. 1

C2-16 Letter Dated January 29, 2014 – COPE Submitting Response to CEC IR No. 1

C2-16-1 Letter Dated January 30, 2014 – COPE 378 Submitting Updated Response to CEC IR No. 1

C2-17 Letter Dated February 5, 2014 – COPE 378 Submitting Late Responses to Information Requests

C2-18 Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to BCSEA IR No. 2

C2-19 Letter Dated February 26, 2014 – COPE 378 Submitting Late Response to CEC IR No. 2

C2-20 Letter Dated February 28, 2014 – COPE 378 Submitting Response FEI-FBC-Objections to CEC IR Responses

C2-21 Letter Dated March 3, 2014 – COPE 378 Submitting Witness Pane

C2-22 Letter Dated April 29, 2014 - COPE 378 Comments regarding CEC Extension Request

C2-23 Letter Dated July 10, 2014 - COPE 378 Submitting Comments regarding Oral Argument Phase

C3-1 **BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BCH)** Online Registration Dated July 4, 2013 – Request for Intervener Status by Janet Fraser

C4-1 **BC SUSTAINABLE ENERGY ASSOCIATION AND THE SIERRA CLUB BRITISH COLUMBIA (BCSEA)** Letter dated July 14, 2013 – Request for Intervener Status by William Andrews and Thomas Hackney

C4-2 Letter dated July 23, 2013 – BCSEA Submitting Confidentiality Undertakings

C4-3 Letter dated July 30, 2013 – BCSEA Submitting Information Request No. 1 to FEI

C4-4 Letter dated August 29, 2013 – BCSEA Submitting Consultants Confidentiality Undertakings

C4-5 Letter dated November 1, 2013 – BCSEA Submitting Information Request No. 2 Non-PBR

C4-6 Letter dated November 15, 2013 – BCSEA Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C4-7 Letter dated December 16, 2013 - BCSEA Submitting Filing Extension Request and Comments

C4-8 Letter Dated December 20, 2013 – BCSEA Submitting Evidence

C4-8-1 **CONFIDENTIAL** - Table 7 Cost-Effectiveness of Retrofit vs Natural Replacement of Furnaces

C4-9 Letter Dated December 23, 2013 – Response to Exhibit A-17 regarding EEC Funding

C4-10 Letter Dated January 13, 2014 – BCSEA Submission on the Remainder of the Regulatory Timetable

C4-11 Letter Dated January 16, 2014 – BCSEA Submitting Information Request No. 1 to CEC

C4-12	Letter Dated January 16, 2014 – BCSEA Submitting Information Request No. 1 to COPE
C4-13	Letter Dated January 29, 2014 – BCSEA Submitting Response to BCUC IR No. 1
C4-14	Letter Dated January 29, 2014 – BCSEA Submitting Response to FEI-FBC IR No. 1
C4-14-1	**CONFIDENTIAL** Letter Dated January 29, 2014 – BCSEA Submitting Confidential Response to FEI-FBC IR No. 1
C4-15	Letter Dated January 29, 2014 – BCSEA Submitting Response to BCPSO IR No. 1
C4-16	Letter Dated February 12, 2014 – BCSEA Submitting IR No. 2 to CEC on Intervener Evidence
C4-17	Letter Dated February 12, 2014 – BCSEA Submitting IR No. 2 to COPE on Intervener Evidence
C4-18	Letter Dated February 25, 2014 – BCSEA Submitting Response to CEC IR No. 2
C4-19	Letter Dated February 25, 2014 – BCSEA Submitting Response to BCUC IR No. 2
C4-20	Letter Dated February 28, 2014 – BCSEA Submitting Comment on FEI-FBC-Objections to CEC IR Responses
C4-21	Letter Dated February 28, 2014 – BCSEA Submitting Notice
C4-22	Letter Submitted March 10, 2014 – BCSEA Submitting Opening Statement Presentation
C4-23	Letter Dated March 28, 2014 – BCSEA Information Request No. 1 to FEU on Rebuttal Evidence
C4-24	Letter Dated May 1, 2014 - BCSEA Comments regarding CEC Extension Request
C5-1	**BRITISH COLUMBIA PENSIONERS' AND SENIORS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, BC COALITION OF PEOPLE WITH DISABILITIES, COUNSEL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCPSO)** Letter dated July 15, 2013 – Request for Intervener Status by Tannis Braithwaite, Eugene Kung and James Wightman

C5-2 Letter dated July 29, 2013 – BCPSO Submitting Confidentiality Undertakings

C5-3 Letter dated July 30, 2013 – BCPSO Submitting Information Request No. 1 to FEI

C5-4 Letter dated November 1, 2013 – BCPSO Submitting Information Request No. 2 Non-PBR

C5-5 Letter dated November 15, 2013 – BCPSO Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C5-6 Letter Dated December 19, 2013 – BCPSO Submitting Evidence

C5-7 Letter Dated December 20, 2013 – BCPSO Submission on EEC Funds

C5-8 Letter Dated January 13, 2014 – BCPSO Submission on the Remainder of the Regulatory Timetable

C5-9 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to BCSEA

C5-10 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to CEC

C5-11 Letter Dated January 16, 2014 – BCPSO Submitting Information Request No. 1 to COPE

C5-12 Letter Dated January 29, 2014 – BCPSO Submitting Response to BCUC IR No. 1

C5-13 Letter Dated January 29, 2014 – BCPSO Submitting Response to FEI-FBC IR No. 1

C5-14 Letter Dated February 12, 2014 – BCPSO Submitting IR No. 2 to CEC on Intervener Evidence

C5-15 Letter Dated February 26, 2014 – BCPSO Submitting Response to BCUC IR No. 2

C5-16 Letter Dated February 26, 2014 – BCPSO Submitting Response to CEC IR No. 2

C5-16-1 Letter Submitted March 3, 2014 – BCPSO Filing Response to CEC IR No.2.2.3

C5-17 Letter Dated March 3, 2014 – BCPSO Submitting Comments regarding FEI-FBC Objection to CEC IR Responses

C5-18 Letter Dated March 3, 2014 – BCPSO Submitting Witness Panel

C5-19 Letter Dated April 30, 2014 - BCPSO Comments regarding CEC Extension Request

C6-1 **COALITION FOR OPEN COMPETITION (COC)** Letter dated July 16, 2013 – Request for Intervener Status by Ronald L. Cliff, Dana M. Taylor, Martin Luymes, Philip Hochstein and Doug Wall

C6-2 Letter dated July 30, 2013 – COC Submitting Information Request No. 1 to FEI

C6-3 Letter dated November 1, 2013 – COC Submitting Information Request No. 2 Non-PBR

C6-4 Letter dated November 15, 2013 – COC Submitting Information Request No. 2 on Performance Based Rates Methodology issues

C6-5 Letter Dated January 13, 2014 – COC Submission on the Remainder of the Regulatory Timetable

C7-1 **MINISTRY OF ENERGY AND MINES (MEM)** Online Registration and Letter dated July 16, 2013 – Request for Intervener Status by Erik Kaye

C12-1 Submitted at Oral Hearing March 11, 2014 – COPE Letter from Jim Quail with Attached Evidence of Barbara R. Alexander dated December 18, 2013

C12-2 Submitted at Oral Hearing March 11, 2014 – CEC Opening Comments… 2014 through 2018

C12-3 Submitted at Oral Hearing March 12, 2014 – COPE Opening Statement of Barbara R. Alexander on behalf of COPE Local 378

C12-4 Submitted at Oral Hearing March 12, 2014 – CEC Opening Comments on B&V's Rebuttal Testimony, Mark Lowry dated 12 March 2014

C12-5 Submitted at Oral Hearing March 14, 2014 – COPE 378 Extracted Reference Exhibits for Cross-Examination of FortisBC Witness Panel No. 2

C12-6 Submitted at Oral Hearing March 17, 2014 – Extracts from FortisBC Electric Final Argument in the 2012-2013 RRA and ISP Proceeding

C12-7 Submitted at Oral Hearing March 17, 2014 – One-Page Petition with 16 Signatures

C12-8 Submitted March 19, 2014 – COPE Undertaking-Hearing Date March 14, 2014 Volume 5, Page 1010, Line 7 to 12

Table 5 Total Cost Sample

Company Name	Number of Customers (2016)	Company Name	Number of Customers (2016)
Alabama Power Company	1,468,744	**London Hydro**	**155,496**
ALLETE (Minnesota Power)	145,622	Louisville Gas and Electric Company	404,744
Appalachian Power Company	956,718	Madison Gas and Electric Company	150,491
Arizona Public Service Company	1,193,511	MDU Resources Group, Inc.	142,948
Atlantic City Electric Company	548,442	Metropolitan Edison Company	562,850
Avista Corporation	374,507	Mississippi Power Company	187,553
Baltimore Gas and Electric Company	1,268,995	Monongahela Power Company	389,759
Black Hills Power, Inc.	71,081	Nevada Power Company	903,198
Central Hudson Gas & Electric Corporation	261,411	New York State Electric & Gas Corporation	890,260
Central Maine Power Company	619,312	Niagara Mohawk Power Corporation	1,323,415
Cleco Power LLC	288,013	Northern Indiana Public Service Company	464,146
Cleveland Electric Illuminating Company	747,748	Northern States Power Company - MN	1,454,285
Commonwealth Edison Company	3,953,907	Northern States Power Company - WI	256,540
Connecticut Light and Power Company	1,238,337	Ohio Edison Company	1,041,123
Consolidated Edison Company of New York,	3,420,121	Oklahoma Gas and Electric Company	830,057
Consumers Energy Company	1,804,630	Orange and Rockland Utilities, Inc.	229,533
Delmarva Power & Light Company	516,709	Pacific Gas and Electric Company	5,428,390
DTE Electric Company	2,169,416	PECO Energy Company	1,613,041
Duke Energy Carolinas, LLC	2,519,317	Pennsylvania Electric Company	587,251
Duke Energy Florida, LLC	1,743,136	Pennsylvania Power Company	164,285
Duke Energy Indiana, LLC	812,986	Portland General Electric Company	859,396
Duke Energy Kentucky, Inc.	140,014	Potomac Electric Power Company	848,171
Duke Energy Ohio, Inc.	706,793	PPL Electric Utilities Corporation	1,426,676
Duke Energy Progress, LLC	1,526,422	Public Service Company of Colorado	1,441,982
Duquesne Light Company	587,954	Public Service Company of New Hampshire	507,998
El Paso Electric Company	408,504	Public Service Company of Oklahoma	547,142
Empire District Electric Company	170,529	Public Service Electric and Gas Company	2,227,065
Enersource Mississauga	**204,728**	Puget Sound Energy, Inc.	1,119,711
Entergy Arkansas, Inc.	706,879	San Diego Gas & Electric Co.	1,425,132
Entergy Mississippi, Inc.	446,654	South Carolina Electric & Gas Co.	705,025
Entergy New Orleans, Inc.	198,416	Southern California Edison Company	5,049,192
EnWin	**87,901**	Southern Indiana Gas and Electric Company, Inc.	148,429
Florida Power & Light Company	4,840,266	Southwestern Public Service Company	389,483
Gulf Power Company	453,136	Tampa Electric Company	730,503
Horizon Utilities	**244,114**	**Toronto Hydro**	**761,920**
Hydro Ottawa	**327,880**	Toledo Edison Company	309,060
Idaho Power Co.	529,901	Tucson Electric Power Company	419,845
Indiana Michigan Power Company	589,041	Union Electric Company	1,208,934
Indianapolis Power & Light Company	486,827	United Illuminating Company	332,381
Jersey Central Power & Light Company	1,113,459	Virginia Electric and Power Company	2,550,018
Kansas City Power & Light Company	531,630	West Penn Power Company	723,352
Kansas Gas and Electric Company	325,932	Western Massachusetts Electric Company	209,939
Kentucky Power Company	168,848	Wisconsin Electric Power Company	1,142,983
Kentucky Utilities Company	547,069	Wisconsin Power and Light Company	466,052
Kitchener-Wilmont Hydro	**94,058**	Wisconsin Public Service Corporation	449,877

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Robust Standard Error Estimators for Panel Models: A Unifying Approach

Giovanni Millo
Group Insurance Research, Generali SpA
DEAMS, University of Trieste

Abstract

The different robust estimators for the standard errors of panel models used in applied econometric practice can all be written and computed as combinations of the same simple building blocks. A framework based on high-level wrapper functions for most common usage and basic computational elements to be combined at will, coupling user-friendliness with flexibility, is integrated in the **plm** package for panel data econometrics in R. Statistical motivation and computational approach are reviewed, and applied examples are provided.

Keywords: panel data, covariance matrix estimators, R.

1. Introduction

This paper is about computing estimators for the covariance matrix of parameters in a linear panel model, of the kind commonly used in applied practice to produce "robust" standard errors. Different estimators are usually preferred in one or the other branch of applied econometrics, from large microeconometric panels (Arellano 1987) to moderately-sized panel time series in macroeconomics (Driscoll and Kraay 1998) and large panels in finance (Petersen 2009; Cameron, Gelbach, and Miller 2011; Thompson 2011), up to pooled time series in political science (Beck and Katz 1995). Software implementations are in most cases to be found in one or the other commercial package, often as user-programmed additional routines; or sometimes GAUSS (Aptech Systems, Inc. 2006) or MATLAB (The MathWorks Inc. 2017) code is available. My work aims at bringing them all together under the common umbrella of the R environment (R Core Team 2017), once again the all-purpose statistical software.

From a software design viewpoint, I translate some results from the recent literature (Petersen 2009; Thompson 2011; Cameron *et al.* 2011) into a comprehensive computational framework, in turn integrated into the **plm** package for panel data econometrics (Croissant and Millo

2008). I describe a general expression for "clustering" estimators; then I review two-level clustering as a combination of simple clustering estimators and the extension to persistent effects by summation of lagged terms; lastly, I show how applying a weighting scheme to lagged covariance terms yields Driscoll and Kraay (1998)'s spatial correlation consistent (SCC) estimator (and, as a special case, that of Newey and West 1987).

From an application perspective, I extend the treatment of Petersen (2009) to double-clustering estimators plus time-persistent shocks as in Thompson (2011): a structure which, based on simulations in Petersen (2009), can be conjectured to successfully account for both individual effects and persistent idiosyncratic shocks. My approach also allows easy extension to a combination of effects which has not, to my knowledge, received attention in the literature yet: double-clustering as in Cameron *et al.* (2011) plus time-decaying correlation as in Driscoll and Kraay (1998). A practical example is given in Section 6.

One not-so-minor aim of this paper is to overcome sectoral barriers between different, if contiguous, disciplines: it is striking, for example, how few citations Driscoll and Kraay (1998) on the panel generalization of the Newey and West (1987) estimator gets in the finance literature, especially in those papers that advocate what is essentially an unweighted version of their SCC covariance. Also, Arellano (1987) and Froot (1989), in the different contexts of fixed effects panels with serial correlation and of industry-clustered financial data, independently developed what is computationally the same estimator (referred in the following as one-way clustering) first described by Liang and Zeger (1986). Cross-referencing between the different branches of statistical and econometric research is still uncommon in this subject, to the point that raising awareness might be useful.[1] From the point of view of political science, where panel – or time-series cross-section (TSCS) – data are an important methodological field, the functionality outlined here allows researchers to progress beyond the now-ubiquitous application of panel-corrected standard errors (PCSE, Beck and Katz 1995) to pooled specifications, along the lines of Wilson and Butler (2007): both comparing it with alternative strategies and possibly combining it with individual effects, in order to tackle the all-important, and often overlooked, issue of individual heterogeneity (Wilson and Butler 2007, Section 2.2).

In this sense, my work is meant to provide R users with a comprehensive set of modular tools: lower level components, conceptually corresponding to the statistical "objects" involved (see Zeileis 2006), and a higher-level set of "wrapper functions" corresponding to standard covariance estimators as they would be used in statistical packages: White heteroskedasticity-consistent, clustering, SCC and so on. Wrappers work by combining the same, few lower-level components in multiple ways in the spirit of the *Lego principle* of Hothorn, Hornik, Van De Wiel, and Zeileis (2006), with obvious benefits for both flexibility and code maintenance. This toolset should enable users to follow the work of Petersen (2009); Cameron *et al.* (2011); Thompson (2011) in detail, experimenting with settings and comparing estimates' magnitudes (see Petersen 2009) for specification and diagnostic purposes, at least as far as linear models in two panel dimensions are concerned.

Clustered standard errors for non-panel models are another field of application. For some time, there has been R code available for one- or two-way clustering in a linear model (see Arai 2009). This last has recently evolved into a package for multi-way clustering, **multiwayvcov**

[1] Also note that Fama and MacBeth (1973)'s covariance estimator popular in finance, actually first and foremost an estimator for the averages of the coefficients, is known in the econometrics literature as the Mean Group estimator of Pesaran and Smith (1995). See Ibragimov and Müller (2010) for a formal justification of the Fama-MacBeth method.

(Graham, Arai, and Hagströmer 2016); in turn, many of the features of the latter have been incorporated into the **sandwich** package by Berger, Graham, and Zeileis (2017). The **sandwich** package was the original, object-oriented implementation of sandwich estimators in R (Zeileis 2006) and provides the generic function `vcovHC`, panel methods for which are presented here. Nevertheless, up to two clustering dimensions all this functionality is effectively encompassed by that presented here, provided the data are treated like a *faux* panel specifying one or two indices. Moreover, integration within the **plm** package means that the estimators presented here can seamlessly interact with panel features like individual or time effects. By contrast, extending clustering to more than two dimensions in a panel context does not fit into the panel data infrastructure of package **plm** and is out of the scope of this paper.

When estimating regression models, R creates a model object which, besides estimation results, carries on a wealth of useful information, including the original data. Robust testing in R is done retrieving the necessary elements from the model object, using them to calculate a robust covariance matrix for coefficient estimates and then feeding the latter to the actual test function, which can be a t-test for significance, a Wald restriction test and so on. Therefore the approach to diagnostic testing is more flexible than with procedural languages, where diagnostics usually come with standard output. In our case, for example, one can obtain different estimates of the standard errors under various kinds of dependence without re-estimating the model, and present them compactly.

When appropriate, I will highlight some features of R that make it easy and effective to combine statistical objects; in particular, functions as arguments; modularity and components reusing; function application over arrays of arbitrary dimension; and in general object orientation, which ensures application of the right method with the appropriate defaults for the object at hand through standard syntax.

The paper is organized into three main bodies. The next two sections (Sections 2 and 3) review the statistical foundations of the methods and set the notation in terms of a few low-level components according to the Lego principle. Section 4 on the computational framework, arguably the heart of the paper, describes the statistical building blocks in terms of computational objects characterized by a few standard "switches", and their combinations in terms of user-friendly "wrapper" functions; then, in an object-oriented fashion, it discusses how and when it is (statistically) appropriate to apply the resulting user-level methods to '`plm`' objects estimated in different ways: by either (pooled) ordinary least squares (OLS), fixed effects (FE), random effects (RE), or by first-differencing methods (FD). The remainder of the paper (Sections 5 and 6) sets the new estimators in the context of the **plm** package and provides some examples of application.

The functionality described here is available in package **plm** since version 1.5-1 and the package is available from the Comprehensive R Archive Network (CRAN) at `https://CRAN.R-project.org/package=plm`.

2. Robust covariance estimators

In this section I briefly review the ideas behind robust covariance estimators of the *sandwich* type, in order to provide a basis for the subsequent treatment of their panel extension. The reader is referred to any econometrics textbook, e.g., Greene (2003) – on which this paragraph is based – for a formal treatment.

Consider a linear model $y = X\beta + \epsilon$ and the OLS estimator $\hat{\beta}_{OLS} = (X^\top X)^{-1}X^\top y$. If one is interested in making inference on β, then an estimate of $\mathsf{VAR}(\hat{\beta})$ is needed. If the error terms ϵ are independent and identically distributed, then the covariance matrix takes the familiar textbook form: $\mathsf{VAR}(\hat{\beta}) = \hat{\sigma}^2(X^\top X)^{-1}$, where $\hat{\sigma}^2$ is an estimate of the error variance. This case is synthetically dubbed *spherical errors*, and the relative formulation of $V(\hat{\beta}_{OLS})$ is often referred to, somewhat inappropriately, as "OLS covariance"[2].

Let us consider robust estimation in the context of the simple linear model outlined above. The problem at hand is to estimate the covariance matrix of the OLS estimator relaxing the assumptions of serial correlation and/or homoskedasticity without imposing any particular structure to the errors' variance or interdependence.

As the estimator of the OLS parameters' covariance matrix is

$$\hat{V} = \frac{1}{n}\left(\frac{X^\top X}{n}\right)^{-1}\left(\frac{1}{n}X^\top[\sigma^2\Omega]X\right)\left(\frac{X^\top X}{n}\right)^{-1}$$

in order to consistently estimate V it is not necessary to estimate all the $n(n+1)/2$ unknown elements in the Ω matrix but only the $K(K+1)/2$ ones in

$$\frac{1}{n}\sum_{i=1}^{n}\sum_{j=1}^{n}\sigma_{ij}\mathbf{x}_i\mathbf{x}_j^\top,$$

which may be called the *meat* of the sandwich, the two $\left(\frac{X^\top X}{n}\right)^{-1}$ being the *bread*. (From now on, we will concentrate exclusively on the meat, and we will dispose of the $1/n$ terms throughout.) All that is required are *pointwise consistent* estimates of the errors, which is satisfied by consistency of the estimator for β (see Greene 2003). In the heteroskedasticity case, correlation between different observations is ruled out and the *meat* reduces to

$$S_0 = \frac{1}{n}\sum_{i=1}^{n}\sigma_i^2\mathbf{x}_i\mathbf{x}_i^\top,$$

where the n unknown σ_i^2s can be substituted by e_i^2 (see White 1980). In the serial correlation case, the natural estimation counterpart would be

$$\frac{1}{n}\sum_{i=1}^{n}\sum_{j=1}^{n}e_ie_j\mathbf{x}_i\mathbf{x}_j^\top,$$

but this structure proves too general to achieve convergence. Newey and West (1987) devise a (heteroskedasticity and) autocorrelation consistent estimator that works based on the assumption of correlation dying out as the distance between observations increases. The Newey-West HAC estimator for the *meat* takes that of White and adds a sum of covariances between the different residuals, smoothed out by a *kernel function* giving weights decreasing with distance:

[2]The reason is that OLS is "best linear unbiased" (BLUE) under sphericity; yet this is confusing because other covariance estimators can be more appropriate for $\hat{\beta}_{OLS}$ under different conditions. Notice that Thompson (2011) uses the same name referring to the case of heteroskedasticity but no dependence (here: *White*).

$$S_0 + \frac{1}{n}\sum_{i=1}^{n}\sum_{j=1}^{n} w_l e_t e_{t-l}\left(\mathbf{x}_t \mathbf{x}_{t-l}^\top + \mathbf{x}_{t-l}\mathbf{x}_t^\top\right)$$

with w_l the weight from the kernel smoother, e.g., the Bartlett kernel function: $w_l = 1 - \frac{l}{L+1}$ (for a discussion of alternative kernels see Zeileis 2006). The lag l is usually truncated well below sample size: one popular rule of thumb is $L = n^{1/4}$ (see Greene 2003; Driscoll and Kraay 1998).

In the following I will consider the extensions of this framework for a panel data setting where, thanks to added dimensionality, various combinations of the two above structures will turn out to be able to accommodate very general types of dependence.

3. Clustering estimators in a panel setting

Let us now consider a *panel* (or *longitudinal*) setting where data are collected on two different dimensions: to fix ideas, let us think of n entities (individuals, firms, countries, ...) which we here label *groups* and index by $i = 1, \ldots, n$ sampled at T points in *time*. The two dimensions are not fully symmetric as for the sake of practical relevance I have considered one dimension (time) having a natural ordering and the other having none. This setting is sufficiently general to describe the vast majority of applications; a symmetric extension would nevertheless be straightforward. Different choices of dimensions are possible and have been explored in the literature: e.g., Froot (1989), in the context of financial data, discusses sampling from "independent" industries in order to increase sample size, clustering within industry to account for dependence. Thus the two dimensions would be *industry* and a generic counter: clustering would be done according to industry, while meaningless across the "other" dimension. The model is then

$$y_{it} = X_{it}\beta + \epsilon_{it}.$$

For now I consider again the familiar OLS estimator $\hat{\beta}_{OLS}$, which in this setting is referred to as *pooled OLS* because it *pools* all observations together irrespective of their belonging to a given group (but see Section 4.4 for an extension to three other common panel estimators).

Clustering estimators work by extending the "sandwich" principle to panel data. Besides heteroskedasticity, the added dimensionality allows to obtain robustness against totally unrestricted timewise or cross-sectional correlation, provided this is along the "smaller" dimension. In the case of "large-N" (*wide*) panels, the big cross-sectional dimension allows robustness against serial correlation[3]; in "large-T" (*long*) panels, on the converse, robustness to cross-sectional correlation can be attained drawing on the large number of time periods observed. As a general rule, the estimator is asymptotic in the number of clusters: see Cameron *et al.* (2011, Section 2).

Imposing cross-sectional (serial) independence in fact restricts all covariances between observations belonging to different individuals (time periods) to zero, yielding an error covariance

[3]This is the case of the seminal contribution by Arellano (1987).

matrix with a block-diagonal structure: in the former case, $V(\epsilon) = I_n \otimes \Omega_i$, where

$$\Omega_i = \begin{bmatrix} \sigma_{i1}^2 & \sigma_{i1,i2} & \dots & \dots & \sigma_{i1,iT} \\ \sigma_{i2,i1} & \sigma_{i2}^2 & & & \vdots \\ \vdots & & \ddots & & \vdots \\ \vdots & & & \sigma_{iT-1}^2 & \sigma_{iT-1,iT} \\ \sigma_{iT,i1} & \dots & \dots & \sigma_{iT,iT-1} & \sigma_{iT}^2 \end{bmatrix} \quad (1)$$

and the consistency relies on the cross-sectional dimension being "large enough" with respect to the number of free covariance parameters in the diagonal blocks. The other case is symmetric.

3.1. White-Arellano, or one-way clustering

White's heteroskedasticity-consistent covariance matrix[4] has been extended to clustered data by Liang and Zeger (1986) and to econometric panel data by Arellano (1987), who applied it in a fixed effects setting. Observations can be clustered by the cross-sectional (group) index which is arguably the most popular use of this estimator, and is appropriate in *large, short* panels because it is based on n-asymptotics; or by the time index, which is based on T-asymptotics and therefore appropriate for *long* panels. In the first case, the covariance estimator is robust against cross-sectional heteroskedasticity and also against serial correlation of arbitrary form. In the second case, symmetrically, against timewise heteroskedasticity and cross-sectional correlation. Arellano's original estimator, an instance of the first case, has the form:

$$V_{\text{White-Arellano}} = (X^\top X)^{-1} \sum_{i=1}^{n} X_i^\top u_i u_i^\top X_i (X^\top X)^{-1}. \quad (2)$$

It is of course still feasible to rule out serial correlation and compute an estimator that is robust to heteroskedasticity only, based on the following error structure:

$$\Omega_i = \begin{bmatrix} \sigma_{i1}^2 & \dots & \dots & 0 \\ 0 & \sigma_{i2}^2 & & \vdots \\ \vdots & & \ddots & 0 \\ 0 & \dots & \dots & \sigma_{iT}^2 \end{bmatrix} \quad (3)$$

in which case the original White estimator applies:

$$V_{\text{White}} = (X^\top X)^{-1} \sum_{i=1}^{n} \sum_{t=1}^{T} u_{it}^2 \mathbf{x}_{it} \mathbf{x}_{it}^\top (X^\top X)^{-1}. \quad (4)$$

Some notation

Before discussing bidirectional extensions of this estimator, for the sake of clarity I will now define the "meat" of the two versions of the Arellano estimator, henceforth $V_{C\cdot}$, with respect to

[4] See White (1980, 1984).

the clustering dimension: the original, group-clustered version, robust vs. heteroskedasticity and *serial* dependence, will be

$$V_{CX} = \sum_{i=1}^{n} X_i^\top u_i u_i^\top X_i, \tag{5}$$

while the time-clustered version, robust vs. heteroskedasticity and *cross-sectional* dependence, will be:

$$V_{CT} = \sum_{t=1}^{T} X_t^\top u_t u_t^\top X_t. \tag{6}$$

The standard White estimator on pooled data, which is symmetric w.r.t. clustering,

$$V_W = \sum_{t=1}^{T} \sum_{i=1}^{n} u_{it}^2 \mathbf{x}_{it} \mathbf{x}_{it}^\top \tag{7}$$

will be conveniently written as

$$V_W = \sum_{i=1}^{n} X_i^\top \mathrm{diag}(u_i^2) X_i = \sum_{t=1}^{T} X_t^\top \mathrm{diag}(u_t^2) X_t, \tag{8}$$

where $\mathrm{diag}(u^2)$ is a matrix with squares of elements of u on the diagonal and zeros elsewhere, so that all of these expressions share the common structure

$$V_{C\cdot} = \sum_{\cdot} X_\cdot^\top \mathsf{E}(u) X. \tag{9}$$

with $\mathsf{E}(u)$ an appropriate function of the residuals.

This symmetric representation will provide a good starting point for the extension to double clustering.

3.2. Double clustering

Some recent research in finance (Petersen 2009; Cameron *et al.* 2011; Thompson 2011) advocates double clustering, motivating it by the need to account for *persistent shocks* and at the same time for cross-sectional or spatial correlation.

This estimator combining both individual and time clustering relies on a combination of the asymptotics of each: the minimum number of clusters along the two dimensions must go to infinity: see, again, Cameron *et al.* (2011, Section 2). Apart from this, any dependence structure is allowed within each group *or* within each time period, while cross-serial correlations between observations belonging to different groups *and* time periods are ruled out.

The double-clustered estimator is easily calculated by summing up the group-clustering and the time-clustering ones, then subtracting the standard White estimator (referred to in Cameron *et al.* 2011 as *time-group-clustering*, in Thompson 2011 as *white0*) in order to avoid double-counting the error variances along the diagonal:

$$V_{CXT} = V_{CX} + V_{CT} - V_W. \tag{10}$$

In order to control for the effect of common shocks, Thompson (2011) proposes to add to the sum of covariances one more term, related to the covariances between observations from any group at different points in time. Given a maximum lag L, this will be the sum over $l = 1, \ldots, L$ of the following generic term:

$$V_{CT,l} = \sum_{t=1}^{T} X_t^\top u_t u_{t-l}^\top X_{t-l} \tag{11}$$

representing the covariance between pairs of observations from any group distanced l periods in time, summed with its transpose. As the correlation between observations belonging to the *same* group at different points in time has already been captured by the group-clustering term, to avoid double counting one must subtract the within-groups part:

$$V_{W,l} = \sum_{t=1}^{T} \sum_{i=1}^{n} [x_{it} u_{it} u_{i,t-l}^\top x_{i,t-l}^\top] \tag{12}$$

again summed with its transpose, for each l. The resulting estimator

$$V_{CXT,L} = V_{CX} + V_{CT} - V_W + \sum_{l=1}^{L} [V_{CT,l} + V_{CT,l}^\top] - \sum_{l=1}^{L} [V_{W,l} + V_{W,l}^\top] \tag{13}$$

is robust to cross-sectional and timewise correlation inside, respectively, time periods and groups *and* to the cross-serial correlation between observations belonging to different groups, up to the Lth lag. It also resembles another well-known estimator from the econometric literature: the Newey-West nonparametric estimator, the difference being that instead of adding a (possibly truncated) sum of unweighted lag terms, the latter downweighs the correlation between "distant" terms through a kernel smoother function. Kernel-smoothed estimators will be the subject of the next section.

3.3. Kernel-based smoothing

As cited above, in a time series context Newey and West (1987) proposed an estimator that is robust to serial correlation as well as to heteroskedasticity. This estimator, based on the hypothesis of the serial correlation dying out "quickly enough", takes into account the covariance between units by: weighting it through a kernel smoother function giving less weight as they get more distant; and adding it to the standard White estimator.

Driscoll and Kraay's "SCC"

Driscoll and Kraay (1998) adapted the Newey-West estimator to a panel time series context, where not only serial correlation between residuals from the same individual in different time periods is taken into account, but also cross-serial correlation between different individuals in different times and, within the same period, cross-sectional correlation (see also Arellano 2003, p. 19).

The Driscoll and Kraay estimator, labeled SCC (as in "spatial correlation consistent"), is defined as the time-clustering version of Arellano plus a sum of lagged covariance terms, weighted by a distance-decreasing kernel function w_l:

$$\begin{aligned} V_{SCC,L} &= V_{CT} + \textstyle\sum_{l=1}^{L} w_l [\sum_{t=1}^{T} X_t^\top u_t u_{t-l}^\top X_{t-l} + \sum_{t=1}^{T} [X_t^\top u_t u_{t-l}^\top X_{t-l}]^\top] \\ &= V_{CT} + \textstyle\sum_{l=1}^{L} w_l [V_{CT,l} + V_{CT,l}^\top]. \end{aligned} \tag{14}$$

The "scc" covariance estimator requires the data to be a mixing sequence, i.e., roughly speaking, to have serial and cross-serial dependence dying out quickly enough with the T dimension, which is therefore supposed to be fairly large: Driscoll and Kraay (1998), based on Monte Carlo simulation, put the practical minimum at $T > 20 - 25$; the n dimension is irrelevant in this respect and is allowed to grow at any rate relative to T.

Panel Newey-West

By restricting the cross-sectional and cross-serial correlation to zero one gets a "pure" panel version of the original Newey-West estimator, as discussed, e.g., in Petersen (2009):

$$\begin{aligned} V_{NW,L} &= V_W + \textstyle\sum_{l=1}^{L} w_l [\sum_{t=1}^{T} \sum_{i=1}^{n} [\mathbf{x}_{it} u_{it} u_{i,t-l}^\top \mathbf{x}_{i,t-l}^\top] + \sum_{t=1}^{T} [\sum_{i=1}^{n} [\mathbf{x}_{it} u_{it} u_{i,t-l}^\top \mathbf{x}_{i,t-l}^\top]^\top] \\ &= V_W + \textstyle\sum_{l=1}^{L} w_l [V_{W,l} + V_{W,l}^\top]. \end{aligned} \tag{15}$$

As is apparent from Equation 14, if the maximum lag order is set to 0 (no serial or cross-serial dependence is allowed) the SCC estimator reverts to the cross-section version (time-clustering) of the Arellano estimator V_{CT}. On the other hand, if the cross-serial terms are all unweighted (i.e., if $w_l = 1 \, \forall l$) then $V_{SCC,L|w=1} = V_{CT,L}$.

3.4. Unconditional estimators

Unconditional covariance estimators are based on the assumption of no error correlation in time (cross-section) and of an unrestricted but invariant correlation structure inside every cross-section (time period). They are popular in contexts characterized by relatively small samples, with prevalence of the time dimension.

Beck and Katz PCSE

Beck and Katz (1995), in the context of political science models with moderate time and cross-sectional dimensions, introduced the so-called panel corrected standard errors (PCSE), an estimator with good small-sample properties which, in the original time-clustering setting, is robust against cross-sectional heteroskedasticity and correlation.

In this framework and with reference to Equation 9, the "pcse" covariance is defined in terms of the $E_i = E \;\; \forall i$ function of the residuals as:

$$E = \frac{\sum_n \hat{e}_n \hat{e}_n^\top}{N}.$$

A sufficient, although not necessary condition for consistency of the "pcse" estimator (Beck and Katz 1996) is that the covariance matrix of the errors in every group be the same: $\Omega = \Sigma \otimes I_T$, with

$$\Sigma = \begin{bmatrix} \sigma_1^2 & \sigma_{1,2} & \cdots & \cdots & \sigma_{1,T} \\ \sigma_{2,1} & \sigma_2^2 & & & \vdots \\ \vdots & & \ddots & & \vdots \\ \vdots & & & \sigma_{T-1}^2 & \sigma_{T-1,T} \\ \sigma_{T,1} & \cdots & \cdots & \sigma_{T,T-1} & \sigma_T^2. \end{bmatrix} \tag{16}$$

A possible further restriction is to assume correlation away imposing that Σ be diagonal, thus restricting the estimator to unconditional intragroup heteroskedasticity.

4. Computational framework

Generalizing the computational problem at hand and dividing it into modules is necessary for writing software that be both full-featured and easy to read and to maintain. In this section I show a generic formulation capable of generating all the estimators considered up to now; in the following I will consider a small-sample correction module. These building blocks will allow to construct a very general covariance estimating function whose usage in various testing environments will then be discussed in the light of object-oriented econometric computing.

Two defining features of R as a programming language are object-orientation and functional nature. In this sense, according to the object-oriented nature of R, in the next paragraph I will formulate a general computing module, the *software counterpart* of the *statistical objects* V_W, V_{CX}, V_{CT}, $V_{W,l}$, $V_{CX,l}$ and $V_{CT,l}$ which are in turn the building blocks for any of the estimators considered here. In turn, according to the functional nature of R, the computing module will be formulated as a function of: a (panel-indexed) vector of errors; an integer lag order; and lastly of a function to be applied to the error vector, taking the lag order as an argument. The ability of R to treat functions as a data type will make the translation of this formalization into software seamless.

4.1. A general, computing-oriented formulation

The most general formulation of the comprehensive estimator can be written as a kernel-weighted version of Formula 3 in Thompson (2011):

$$V_{CXT,L|w} = V_{CT} + \sum_{l=1}^{L} w_l[V_{CT,l} + V_{CT,l}^{\top}] + V_{CX} - V_W - \sum_{l=1}^{L} w_l[V_{W,l} + V_{W,l}^{\top}]. \tag{17}$$

In turn, all building blocks for Equation 17 can be generated by combining a clustering dimension (n or t), a lag order l and a function of the errors f. Starting from the general formulation:

$$V_g(t, l, f) = \sum_{t=1}^{T} X_t^{\top} f(u_t, u_{t-l}) X_{t-l} \tag{18}$$

inserting the outer product function and setting the lag to zero (so that $f(u_t, u_{t-l}) = u_t u_t^{\top}$) we get the time- (group-)clustering estimator

$$V_{CT} = V_g(t, 0, f = u_t u_t^{\top}) \tag{19}$$

and for the "White" terms on the diagonal, with the dot denoting indifferently n or t as clustering dimension,

$$V_W = V_g(\cdot, 0, f = \mathrm{diag}(u_{\cdot}^2)), \tag{20}$$

while for the cross-serial terms

$$V_{CT,l} = V_g(t, l, f = u_t u_{t-l}^{\top}) \tag{21}$$

Label	Notation
White heteroskedastic	V_W
Group clustering	V_{CX}
Time clustering	V_{CT}
Double clustering	$V_{CXT} = V_{CX} + V_{CT} - V_W$
Time clustering + shocks	$V_{CT,L} = V_{CT} + \sum_{l=1}^{L}[V_{CT,l} + V_{CT,l}^\top]$
Panel Newey-West	$V_{NW,L} = V_W + \sum_{l=1}^{L} w_l[V_{W,l} + V_{W,l}^\top]$
Driscoll and Kraay's SCC	$V_{SCC,L} = V_{CT} + \sum_{l=1}^{L} w_l[V_{CT,l} + V_{CT,l}^\top]$
Double-clustering + shocks	$V_{CXT,L} = V_{CT} + \sum_{l=1}^{L}[V_{CT,l} + V_{CT,l}^\top] + V_{CX} - V_W - \sum_{l=1}^{L}[V_{W,l} + V_{W,l}^\top] = V_{CT,L} + V_{CX} - V_{NW,L\vert w=1}$

Table 1: Covariance structures as combinations of the basic building blocks.

and for the purely autoregressive ones:

$$V_{W,l} = V_g(t, l, f = \mathrm{diag}(u_t \times u_{t-l})) \tag{22}$$

(where $\times$ is the element-by-element product) so that by a (possibly weighted) combination of the above we can get all relevant estimators: see Table 1.

As observed, the SCC estimator differs from the (one-way) time-shocks-robust version of the double-clustering à la CGM only by the distance-decaying weighting of the covariances between different periods, so that $V_{CT,L} = V_{SCC,L\vert w=1}$.

Obviously, as there is no natural univariate ordering between individuals, a full generalization encompassing both the double-clustering and a two-way SCC estimator does not seem sensible. For the same reason, while the software components allow fully symmetric operation, i.e., it would be practically feasible to compute a group-clustering version of $V_{SCC,L}$ or $V_{CX,L}$, this is devoid of sense from a statistical viewpoint because the notion of a linear, unidimensional spatial lag is generally meaningless[5].

4.2. Unconditional estimation in the general framework

Unconditional estimators can also be computed from the general formulation by precalculating the unconditional error covariance $E = \frac{\sum_{t=1}^{T} u_t u_t^\top}{T}$ and substituting it inside the generic Equation 17 as a constant matrix:

$$V_{UT} = V_g(t, 0, f = E). \tag{23}$$

One noteworthy feature of R is the ability to treat functions as first-class objects (R Core Team 2017), which means they are just another, although very special, data type and can be fed to another function as argument. So a function might indifferently take as argument a function or a precalculated matrix, which is the case here[6].

[5] Spatial lags, where applicable, are defined in a completely different way based on two-dimensional proximity matrices (see Anselin 1988). One very special case of linear spatial arrangement allowing for a simple definition of lag is Chudik, Pesaran, and Tosetti (2011)'s circular world, where each observation has one neighbor to the left and one to the right. Yet in that setting dependence would have to consider both directions, while serial dependence only originates from the past.

[6] Another example of use of this powerful feature for passing a covariance matrix or the function calculating it is in Zeileis (2006).

4.3. Unbalanced panels

Unbalancedness is one of the major computational nuisances in panel data econometrics. In the case at hand, the problem is to compute the generic formula in Equation 17 taking heed that unbalanced samples will have incomplete groups (time periods) for some t (i). As the ultimate goal of estimation of the *meat* is to average the $k \times k$ matrix products $X_t^\top f(u_t, u_{t-l})X$ over time periods (or, symmetrically, groups), missing data will give rise to empty positions in X_t and, correspondingly, in $f(u_t, u_{t-l})$.

Fortunately, R has two particularly useful features for treating data in a "generic" way, as independent as possible from dimensions: `list` objects and the `apply` family of functions.

In general R makes it relatively easy to deal with unbalanced data through the use of structures like `lists`, very flexible containers which can hold e.g., matrices of different dimensions and on which operators (and, more generally, *functions* of any kind) can be *applied*. The `apply` family has members for working member-by-member on `lists` (`lapply`), subgroup by subgroup on *ragged arrays* (`tapply`) where (possibly heterogeneous) subgroups are defined by a grouping variable, or dimension by dimension on arrays, which is the original use of `apply`. One notable advantage of this operator is that it can work on arbitrary subsets of the array's dimensions, provided the function to be applied is compatible.[7]

If a function is *applied* that allows discarding of `NA` values, one can easily get consistent averaging over multidimensional arrays: in this case, an average of t $k \times k$ bidimensional matrices of uneven dimensions.

An example will clarify things. Let us take an array of three 3×3 matrices with a missing value, and average over the third dimension. By default, missing values propagate throughout operations:

```
R> a <- array(1, dim = c(3, 3, 3))
R> a[1, 1, 1] <- NA
R> apply(a, 1:2, mean)

     [,1] [,2] [,3]
[1,]   NA    1    1
[2,]    1    1    1
[3,]    1    1    1
```

but the default behavior can be overridden forcing discarding of `NA`s:

```
R> apply(a, 1:2, mean, na.rm = TRUE)

     [,1] [,2] [,3]
[1,]    1    1    1
[2,]    1    1    1
[3,]    1    1    1
```

[7]Notable examples of the usefulness of `lists` and *ragged arrays* for unbalanced panel data econometrics are, respectively, one-by-one inversion of lists of submatrices in general GLS calculations and time- (group-) demeaning of data based on grouping indices; both in package **plm**.

In the latter case, the resulting 3×3 matrix will contain all averages computed on the correct number of items (i.e., for the $[1,1]$ position, $(1+1)/2$).

Analogously, in our case it will be convenient to make use of standard tridimensional arrays making a $k \times k \times t$ matrix – basically a "pile" of $X_t^\top f(u_t, u_{t-l})X$ terms – and then *applying* the `mean` function over the third dimension, obtaining an appropriate calculation of Equation 17 as a result. In fact, for every value of t every product involving a missing element will produce an `NA` in the relative $k \times k$ matrix; but then averaging over the T dimension will discard `NA`s and apply the correct denominator.[8]

The same goes for the estimation of the unconditional covariance in Beck and Katz type estimators. This feature, which has been unavailable for unbalanced panels for a while and then has been twice mentioned in the literature as a potentially complicated computational problem (Franzese 1996; Bailey and Katz 2011) is solved nicely and without effort in R by applying (sic!) the above method, which acts as advocated by Franzese (1996), averaging elements in the unconditional covariance matrix on the correct number of observations[9].

4.4. Application to FE, RE and FD models: The demeaning framework

From a software viewpoint, the methods provided here can be transparently applied either to pooled OLS or to any other model represented by a '`plm`' object. As usual, what is computationally feasible is not necessarily sound from a statistical viewpoint.

The application of the above estimators to pooled data is always warranted, subject to the relevant assumptions mentioned before. In some, but not all cases, these can also be applied to random or fixed effects panel models, or models estimated on first-differenced data. The general idea is to use both the covariates and residuals from the transformed (partially or totally demeaned, first differenced) model used in estimation.

In all of these cases the estimator is computed as OLS on transformed data, e.g., in the fixed effects case $\hat{\beta}_{FE} = (\tilde{X}^\top \tilde{X})^{-1}\tilde{X}^\top \tilde{y}$ with $\tilde{y}_{it} = y_{it} - y_{i.}$ and $\tilde{x}_{jit} = x_{jit} - x_{ji.}$ for each $\mathbf{x}_j$ in X; while in the random effects case this time-demeaning is partial and $\tilde{y}_{it} = y_{it} - \theta y_{i.}$ with $0 < \theta < 1$. Sandwich estimators can then be computed by applying the usual formula to the transformed data and residuals $\tilde{u} = \tilde{y} - \tilde{X}\hat{\beta}$: see Arellano (1987) and Wooldridge (2002, Section 10.59) for the fixed effects case, Wooldridge (2002, Chapter 10) in general.

In the following I discuss when it is appropriate to apply clustering estimators to the residuals of demeaned or first-differenced models.

Fixed effects

The fixed effects estimator requires particular caution. In fact, under the hypothesis of spherical errors in the original model, the time-demeaning of data induces a serial correlation $\mathsf{COR}(u_{it}, u_{i,t-1}) = -1/(T-1)$ in the demeaned residuals (see Wooldridge 2002, p. 275).

The White-Arellano estimator has originally been devised for this case. By way of symmetry, it can be used for time-clustered data with time fixed effects. The combination of group-

[8] Of course the most delicate programming issue becomes correct handling of the positions of incomplete u_t subvectors and X_t submatrices in the relevant tth "layer" of the tridimensional array.

[9] This estimation method, based on all available covariances between two given observations, corresponds to the `pairwise` option in the **pcse** function and package (Bailey and Katz 2011); it must be noted, though, that the default option there (`casewise`) is to use a balanced subset of the data.

clustering with time fixed effects and the reverse seems inappropriate because of the serial (cross-sectional) correlation induced by the time- (cross-sectional-) demeaning.

By analogy, the Newey-West type estimators can be safely applied to models with individual fixed effects (for an application, see Golden and Picci 2008), while the time and two-way cases require caution.

Random effects

In the random effects case, as Wooldridge (2002) notes, the quasi-time demeaning procedure removes the random effects reducing the model on transformed data to a pooled regression, thus preserving the properties of the White-type estimators.

By extension of this line of reasoning, all above estimators seem to be applicable to the demeaned data of a random effects model, provided *the transformed errors* meet the relevant assumptions.

First-differences

First-differencing, like fixed effects estimation, removes time-invariant effects. Roughly speaking, the choice between the two rests on the properties of the error term: if it is assumed to be well-behaved in the original data, then FE is the most efficient estimator and is to be preferred; if on the contrary the original errors are believed to behave as a random walk, then first-differencing the data will yield stationary and uncorrelated errors, and is therefore advisable (see Wooldridge 2002, p. 281). Given this, FD estimation is nothing else than OLS on differenced data, and the usual clustering formula applies (see Wooldridge 2002, p. 282). As in the RE case, the statistical properties of the various covariance estimators will depend on whether *the transformed errors* meet the relevant assumptions.

From the viewpoint of software implementation, the application to fixed or random effects and to first-difference models is greatly simplified by the availability in **plm** of a comprehensive data transformation infrastructure, allowing to easily extract the original data from the model object and apply the relevant transformation (see Croissant and Millo 2008).

4.5. Small-sample corrections

Two kinds of small-sample corrections are implemented: corrections for a small number of observations, derived from the work of MacKinnon and White (1985) and summarized in Zeileis (2006), and corrections for a small number of clusters, described in Cameron *et al.* (2011, p. 8).

All work by multiplying each residual by the square root of the appropriate correction factor $\sqrt{c}$, so that the various squares and cross-products of residuals are correctly multiplied by c while the correction can work at vector level, separating the small-sample-correction module from the other logical steps of computation. The cluster-level correction in turn works at single-clustering level, according to the relevant numerosity parameters, as suggested in Cameron *et al.* (2011): therefore small-sample cluster-level corrections for different clustering dimensions are seamlessly combined.

In all these cases $c > 0$, and $c \to 1$ as the total number of observations or, in the latter case, the number of clusters diverge.

5. R implementation

In this section I will first put the covariance estimators in the context of the **plm** package for panel data econometrics and provide a minimal background on robust restriction testing through interoperability between testing functions and covariance estimators. Then I will describe how the new approach detailed in this paper has been implemented, substituting the existing procedures in the simpler cases while extending functionality to the more complex ones. Lastly I will provide some applied examples to illustrate usage.

5.1. plm and generic sandwich estimators

Robust covariance estimators à la White or à la Newey and West for different kinds of regression models are available in package **sandwich** (Zeileis and Lumley 2017) under form of appropriate methods for the generic functions `vcovHC` and `vcovHAC` (Zeileis 2004, 2006). These are designed for data sampled along one dimension, therefore they cannot generally be used for panel data; yet they provide a uniform and flexible software approach which has become standard in the R environment. The procedures described in this paper have therefore been designed to be syntactically compliant with them.

plm (Croissant and Millo 2008) is an R package for panel data econometrics in which an S3 method for '`plm`' objects for the generic function `vcovHC` has long been available, allowing to apply sandwich estimators to panel models in a way that is natural for users of the **sandwich** package. In fact, despite the different structure "under the hood", the user will, e.g., specify a robust covariance for the diagnostics table of a panel model in the same way she would for a linear or a generalized linear model, the object-orientation features of R taking care that the right statistical procedure be applied to the model object at hand. What will change, though, are the defaults: the `vcovHC` method for '`lm`' objects defaults to the original White estimator, while the `vcovHC` method for '`plm`' objects to clustering by groups, both the most obvious choices for the object at hand.

As an example, Munnell (1990) specifies a Cobb-Douglas production function that relates the gross social product (gsp) of a given US state to the input of public capital (pcap), private capital (pc), labor (emp) and state unemployment rate (unemp) added to capture business cycle effects. Considering this model, whose dataset is a built-in example in **plm**,

```
R> library("plm")
R> data("Produc", package = "plm")
R> fm <- log(gsp) ~ log(pcap) + log(pc) + log(emp) + unemp
```

and the function `coeftest` from package **lmtest** (Zeileis and Hothorn 2002) which produces a compact coefficients table allowing for a flexible choice of the covariance matrix, I calculate the "robust" diagnostic table for two statistically equivalent models: OLS by `lm`

```
R> lmmod <- lm(fm, Produc)
R> library("lmtest")
R> library("sandwich")
R> coeftest(lmmod, vcov = vcovHC)

t test of coefficients:
```

```
               Estimate Std. Error t value  Pr(>|t|)
(Intercept)  1.6433023  0.0716070 22.9489 < 2.2e-16 ***
log(pcap)    0.1550070  0.0186973  8.2903 4.668e-16 ***
log(pc)      0.3091902  0.0126283 24.4839 < 2.2e-16 ***
log(emp)     0.5939349  0.0197887 30.0139 < 2.2e-16 ***
unemp       -0.0067330  0.0013501 -4.9872 7.497e-07 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

and pooled OLS by `plm`

```
R> plmmod <- plm(fm, Produc, model = "pooling")
R> coeftest(plmmod, vcov = vcovHC)

t test of coefficients:

               Estimate Std. Error t value  Pr(>|t|)
(Intercept)  1.6433023  0.2441821  6.7298 3.211e-11 ***
log(pcap)    0.1550070  0.0601195  2.5783   0.01010 *
log(pc)      0.3091902  0.0462297  6.6881 4.209e-11 ***
log(emp)     0.5939349  0.0686061  8.6572 < 2.2e-16 ***
unemp       -0.0067330  0.0030904 -2.1787   0.02964 *
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

As can be seen, the estimated SEs will turn out different as the types of the model objects to be tested are different, unless one overrides the defaults: here specifying the `method` as `"white1"` and the small sample correction as `"HC3"` will replicate the `lm` results:

```
R> coeftest(plmmod,
+     vcov = function(x) vcovHC(x, method = "white1", type = "HC3"))

t test of coefficients:

               Estimate Std. Error t value  Pr(>|t|)
(Intercept)  1.6433023  0.0716070 22.9489 < 2.2e-16 ***
log(pcap)    0.1550070  0.0186973  8.2903 4.668e-16 ***
log(pc)      0.3091902  0.0126283 24.4839 < 2.2e-16 ***
log(emp)     0.5939349  0.0197887 30.0139 < 2.2e-16 ***
unemp       -0.0067330  0.0013501 -4.9872 7.497e-07 ***
---
Signif. codes:  0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1
```

As observed, these features have long been present in **plm**, but limited to one-way clustering (see Croissant and Millo 2008, Section 6.7); one-way SCC and the unconditional Beck and Katz (BK) estimator have also been added at a later stage, each one with its own infrastructure. With the exception of BK, this functionality has now been replaced by a combination of a general parameter covariance estimator as in Equation 17 and specific wrappers, replicating its different particularizations for the most common forms of usage.

5.2. The new modular framework

In this section I show how to use the basic "building block": the general estimator in Equation 17. This is unlikely to be much used in practice but it is left available at user level both for educational use and to possibly allow combinations not implemented in the higher-level wrappers. Then I show what is probably going to be the preferred option for practicing econometricians, that is the higher-level wrappers combining different particularizations of the general estimator to obtain one- or two-way clustering or kernel-weighted estimators à la White, Arellano, CGM, NW or DK. Lastly I show how to easily define custom combinations of the above to estimate more complicated covariance structures.

The general parameter covariance estimator has been implemented in R in a function `vcovG` which is the software counterpart to Equation 18 and can be used for calculating $V_{W,l}$, $V_{CT,l}$ or $V_{CX,l}$. This is visible at the user level and can be used as such, leaving the default lag at 0, to calculate V_W, V_{CT} or V_{CX}. According to the formalization in Equation 18, besides a '`plm`' object and a small-sample correction, it takes as arguments a clustering dimension (`cluster`), a function of the errors corresponding to $\mathsf{E}(u)$ in Equation 9 (`inner`) and a lag order. The `inner` argument accepts either one of two strings `"cluster"` or `"white"`, specifying respectively $\mathsf{E}(u) = uu^\top$ and $\mathsf{E}(u) = \text{diag}(u^\top u)$, or a user-supplied function.

Next, I calculate the Arellano estimator V_{CX} by specifying `"group"` as the clustering dimension, `"cluster"` as the inner function and 0 as the lag order:

```
R> vcovG(plmmod, cluster = "group", inner = "cluster", l = 0)

              (Intercept)     log(pcap)        log(pc)       log(emp)
(Intercept)  0.0596248904 -9.637916e-03 -0.0068911857  0.0148866870
log(pcap)   -0.0096379163  3.614354e-03 -0.0002956929 -0.0031157168
log(pc)     -0.0068911857 -2.956929e-04  0.0021371841 -0.0017597732
log(emp)     0.0148866870 -3.115717e-03 -0.0017597732  0.0047067982
unemp        0.0003700792 -8.058266e-05 -0.0000586966  0.0001366349
                    unemp
(Intercept)  3.700792e-04
log(pcap)   -8.058266e-05
log(pc)     -5.869660e-05
log(emp)     1.366349e-04
unemp        9.550671e-06
attr(,"cluster")
[1] "group"
```

For the convenience of the user, a wrapper function `vcovHC` is provided which reproduces the syntax and results of the stand-alone version already available in **plm**, thus ensuring both retrocompatibility with **plm** and naming consistency with the **sandwich** package. Thus, the following statement reproduces the same output as above (suppressed) in a more intuitive way:

```
R> vcovHC(plmmod)
```

Higher-level functions are needed, and provided, in order to produce the double-clustering and kernel-smoothing estimators by (possibly weighted) sums of the former terms. The general tool in this respect, in turn based on `vcovG`, is `vcovSCC`, which computes weighted sums of $V_{\cdot,l}$ according to a weighting function which is by default the Bartlett kernel. Again, this function is available at user level and the default values will yield the Driscoll and Kraay estimator, $V_{SCC,L}$:

```
R> vcovSCC(plmmod)

              (Intercept)     log(pcap)       log(pc)      log(emp)
(Intercept)  0.0226046609 -5.514511e-03 -6.334497e-04  5.759358e-03
log(pcap)   -0.0055145106  1.367029e-03  1.319429e-04 -1.402905e-03
log(pc)     -0.0006334497  1.319429e-04  5.843328e-05 -1.862888e-04
log(emp)     0.0057593584 -1.402905e-03 -1.862888e-04  1.497875e-03
unemp       -0.0003377024  8.428261e-05  3.257782e-06 -8.034358e-05
                    unemp
(Intercept) -3.377024e-04
log(pcap)    8.428261e-05
log(pc)      3.257782e-06
log(emp)    -8.034358e-05
unemp        6.445790e-06
attr(,"cluster")
[1] "time"
```

No weighting (equivalent to passing the constant 1 as the weighting function: `wj = 1`) will produce the building blocks for double-clustering, according to Equation 13, so that V_{CXT} could be easily obtained defining it at user level as:[10]

```
R> myvcovDC <- function(x, ...) {
+    Vcx <- vcovHC(x, cluster = "group", method = "arellano", ...)
+    Vct <- vcovHC(x, cluster = "time", method = "arellano", ...)
+    Vw <- vcovHC(x, method = "white1", ...)
+    return(Vcx + Vct - Vw)
+  }
R> myvcovDC(plmmod)

              (Intercept)     log(pcap)       log(pc)      log(emp)
(Intercept)  0.0635274416 -1.087953e-02 -0.0067108330  0.0159466020
log(pcap)   -0.0108795286  3.809110e-03 -0.0002102193 -0.0033786244
log(pc)     -0.0067108330 -2.102193e-04  0.0020211433 -0.0017355810
log(emp)     0.0159466020 -3.378624e-03 -0.0017355810  0.0049283961
```

[10]Notice the use of the prefix "my" to indicate that this function has been defined by the user in this session, as opposed to built-in functions. This is done only for the sake of clarity, as R leaves complete naming freedom to the user; yet adhering to naming conventions of some sort is advisable in order to avoid inadvertently replacing built-in functions.

```
unemp        0.0002236813 -4.386756e-05 -0.0000544364  0.0000986291
                     unemp
(Intercept)  2.236813e-04
log(pcap)   -4.386756e-05
log(pc)     -5.443640e-05
log(emp)     9.862910e-05
unemp        1.108906e-05
attr(,"cluster")
[1] "group"
```

Again, convenience wrappers are provided to make usage more intuitive: `vcovNW` computes the panel Newey-West estimator $V_{NW,L}$ (output omitted); `vcovDC` the double-clustering one V_{CXT}, which is constructed not unlike `myvcovDC` from the example above, and gives exactly the same output (suppressed):

```
R> vcovDC(plmmod)
```

More complicated structures allowing for two-way clustering and error persistence in the sense of Thompson (2011) are easily obtained by combination, the same way as illustrated above, following the lines of Section 4.1. Below the case of double-clustering plus four periods of persistent (unweighted) shocks à la Thompson (2011) (notice that the weighting function `wj` has been defined as the constant 1 but must still be a function of two arguments):

```
R> myvcovDCS <- function(x, maxlag = NULL, ...) {
+    w1 <- function(j, maxlag) 1
+    VsccL.1 <- vcovSCC(x, maxlag = maxlag, wj = w1, ...)
+    Vcx <- vcovHC(x, cluster = "group", method = "arellano", ...)
+    VnwL.1 <- vcovSCC(x, maxlag = maxlag, inner = "white", wj = w1, ...)
+    return(VsccL.1 + Vcx - VnwL.1)
+  }
R> myvcovDCS(plmmod, maxlag = 4)

              (Intercept)     log(pcap)       log(pc)      log(emp)
(Intercept)  0.0766973526 -0.0160969792 -4.713237e-03  0.0191602519
log(pcap)   -0.0160969792  0.0043713347  2.332514e-04 -0.0042963693
log(pc)     -0.0047132370  0.0002332514  1.066283e-03 -0.0012435555
log(emp)     0.0191602519 -0.0042963693 -1.243556e-03  0.0052481667
unemp       -0.0006069241  0.0001587212 -9.439635e-06 -0.0001351121
                     unemp
(Intercept) -6.069241e-04
log(pcap)    1.587212e-04
log(pc)     -9.439635e-06
log(emp)    -1.351121e-04
unemp        1.403075e-05
attr(,"cluster")
[1] "time"
```

6. Applied examples

In the following applied examples, I will present the complete array of standard error estimates for each estimator in Table 1. A complete array of methods is presented for the sake of illustration; nevertheless one must keep in mind that the sample size and the number of clusters in either cross-section or time might prove inadequate for some estimators, as reported in the reference papers (see in particular Thompson 2011). The examples below must therefore be seen as examples of computational feasibility, not of statistical soundness of each method.

In fact, even limiting to those methods that are not at odds with the given sample size, the strategy of computing standard errors in all potentially sensible ways and taking the most conservative ones does indeed reduce type I error but at the same time decreases the power of the significance test.[11]

Another purpose of this section is to illustrate some ways to efficiently perform such multiple comparisons through some features of R. Looping on a vector of functions is a useful consequence of R treating functions as a data type. For the sake of clarity, let us predefine some functions for calculating the different covariance estimators in Section 4.1 according to the names reported there and with the appropriate parameters (leaving the maximum lag calculation at its default value of $L = T^{\frac{1}{4}}$):

```
R> Vw <- function(x) vcovHC(x, method = "white1")
R> Vcx <- function(x) vcovHC(x, cluster = "group", method = "arellano")
R> Vct <- function(x) vcovHC(x, cluster = "time", method = "arellano")
R> Vcxt <- function(x) Vcx(x) + Vct(x) - Vw(x)
R> Vct.L <- function(x) vcovSCC(x, wj = function(j, maxlag) 1)
R> Vnw.L <- function(x) vcovNW(x)
R> Vscc.L <- function(x) vcovSCC(x)
R> Vcxt.L <- function(x)
+    Vct.L(x) + Vcx(x) - vcovNW(x, wj = function(j, maxlag) 1)
```

then build up a vector of functions on which to loop:

```
R> vcovs <- c(vcov, Vw, Vcx, Vct, Vcxt, Vct.L, Vnw.L, Vscc.L, Vcxt.L)
R> names(vcovs) <- c("OLS", "Vw", "Vcx", "Vct", "Vcxt", "Vct.L", "Vnw.L",
+    "Vscc.L", "Vcxt.L")
```

in order to calculate a comprehensive table of p values from robust estimators:

```
R> cfrtab <- matrix(nrow = length(coef(plmmod)), ncol = 1 + length(vcovs))
R> dimnames(cfrtab) <- list(names(coef(plmmod)), c("Coefficient",
+    paste("s.e.", names(vcovs))))
R> cfrtab[, 1] <- coef(plmmod)
R> for (i in 1:length(vcovs)) {
+    cfrtab[, 1 + i] <- coeftest(plmmod, vcov = vcovs[[i]])[, 2]
+ }
R> print(t(round(cfrtab, 4)))
```

[11] We are grateful to an anonymous reviewer for this observation.

```
            (Intercept) log(pcap) log(pc) log(emp)   unemp
Coefficient      1.6433    0.1550  0.3092   0.5939 -0.0067
s.e. OLS         0.0576    0.0172  0.0103   0.0137  0.0014
s.e. Vw          0.0708    0.0185  0.0125   0.0195  0.0013
s.e. Vcx         0.2442    0.0601  0.0462   0.0686  0.0031
s.e. Vct         0.0944    0.0232  0.0063   0.0246  0.0018
s.e. Vcxt        0.2520    0.0617  0.0450   0.0702  0.0033
s.e. Vct.L       0.1875    0.0461  0.0079   0.0480  0.0031
s.e. Vnw.L       0.1144    0.0299  0.0206   0.0316  0.0020
s.e. Vscc.L      0.1503    0.0370  0.0076   0.0387  0.0025
s.e. Vcxt.L      0.2722    0.0657  0.0389   0.0736  0.0036
```

6.1. PPP regression

This example applies the new combination `Vcxt.L`, which as observed is undocumented in the literature, in the appropriate context of a "long" panel. Its main purpose is to show how to apply the methodology discussed in the paper to linear hypothesis testing.

Coakley, Fuertes, and Smith (2006) present a purchasing power parity (PPP) regression on quarterly data 1973Q1 to 1998Q4 for 17 developed countries, so that $N = 17$ and $T = 104$ which is fairly typical of a "long" panel.[12] The estimated model is

$$\Delta s_{it} = \alpha + \beta(\Delta p - \Delta p^*)_{it} + \nu_{it},$$

where s_{it} is the relative exchange rate against USD and $(\Delta p - \Delta p^*)_{it}$ is the inflation differential between the country and the US.

```
R> data("Parity", package = "plm")
R> fm <- ls ~ ld
R> pppmod <- plm(fm, data = Parity, effect = "twoways")
```

The hypothesis of interest is $\beta = 1$, therefore instead of significance diagnostics we report the corresponding robust Wald test from `linearHypothesis` in package **car** (Fox and Weisberg 2011):

```
R> library("car")
R> linearHypothesis(pppmod, "ld = 1", vcov = Vcxt.L)

Linear hypothesis test

Hypothesis:
ld = 1

Model 1: restricted model
Model 2: ls ~ ld
```

[12] The first of three examples in the original SCC paper (Driscoll and Kraay 1998) is also a purchasing power parity regression, on annual data 1973–1993 for a sample of 107 countries.

```
Note: Coefficient covariance matrix supplied.

  Res.Df Df  Chisq Pr(>Chisq)
1   1648
2   1647  1 2.2942     0.1299
```

6.2. Petersen's artificial data

The last example draws on a well-known simulated dataset, replicating the original results.

To complement his paper, Petersen (2009) produced a simple artificial dataset, which has become an informal benchmark for practitioners. The data can be retrieved from http://www.kellogg.northwestern.edu/faculty/petersen/htm/papers/se/test_data.txt; a copy is provided in the accompanying materials to this article. He provides the following estimates of standard errors: classical, White heteroskedastic, clustered by firm or year, double-clustered by firm and year; and coefficients and standard errors estimated according to the Fama-MacBeth procedure. In the following, I replicate his results in R with **plm**.

```
R> petersen <- read.table(file = "test_data.txt")
R> colnames(petersen) <- c("firmid", "year", "x", "y")
R> ptrmod <- plm(y ~ x, data = petersen, index = c("firmid", "year"),
+    model = "pooling")
R> vcovs <- c(vcov, Vw, Vcx, Vct, Vcxt)
R> names(vcovs) <- c("OLS", "Vw", "Vcx", "Vct", "Vcxt")
R> cfrtab <- matrix(nrow = length(coef(ptrmod)), ncol = 1 + length(vcovs))
R> dimnames(cfrtab) <- list(names(coef(ptrmod)), c("Coefficient",
+    paste("s.e.", names(vcovs))))
R> cfrtab[, 1] <- coef(ptrmod)
R> for(i in 1:length(vcovs)) {
+    cfrtab[, 1 + i] <- coeftest(ptrmod, vcov = vcovs[[i]])[, 2]
+ }
R> print(t(round(cfrtab, 4)))
```

```
            (Intercept)      x
Coefficient      0.0297 1.0348
s.e. OLS         0.0284 0.0286
s.e. Vw          0.0284 0.0284
s.e. Vcx         0.0669 0.0505
s.e. Vct         0.0222 0.0317
s.e. Vcxt        0.0646 0.0525
```

One should notice a small difference w.r.t. the results of Petersen: in fact, to replicate them exactly one shall specify to use the same small sample correction Stata (StataCorp. 2015) uses by default: e.g., in the double-clustering case,

```
R> coeftest(ptrmod, vcov = function(x) vcovDC(x, type = "sss"))[, 2]
```

```
(Intercept)           x
 0.06506392  0.05355802
```

which yields the same results as double-clustering in Petersen's example.[13]

7. Conclusions

I have reviewed the different robust estimators for the standard errors of panel models used in applied econometric practice, representing them as combinations of atomic building blocks, which can be thought of as the computational counterparts of statistical objects. In turn, these have been defined, according to the functional orientation of R, as variations of the same general element obtained by choosing a clustering dimension (group or time), a lag order and a function of the residuals (either the element-by-element or the outer product).

While it is feasible to combine these constituents *ad hoc* at user level, the standard estimators used in applied practice (White, Arellano, Newey-West, Driscoll and Kraay SCC, double clustering) are provided under form of predefined combinations ("wrapper" functions) for the sake of user-friendliness. Nevertheless, the user enjoys the freedom to combine elements at will, possibly experimenting with non-standard solutions.

The software framework described is integrated in the R package **plm**, so that composite covariance methods can be applied to objects representing panel models of different kinds (FE, RE, FD and, obviously, OLS). The estimate of the parameters' covariance thus obtained can in turn be plugged into diagnostic testing functions, producing either significance tables or hypothesis tests. A function is a regular object type in R, hence compact comparisons of standard errors from different (statistical) methods can be produced simply by looping on covariance types, as shown in the examples.

An extension to multiple clustering dimensions as in Cameron *et al.* (2011) is ill-suited to bidimensional econometric panels, and hence out of the scope of this paper; it has recently been implemented in package **multiwayvcov** for linear models (Graham *et al.* 2016), and can foreseeably be adapted to panel settings by combining the latter with demeaning functionality in **plm** (i.e., treating the transformed data as a classical linear model, see Section 4.4) in ways that look fairly straightforward but are out of the scope of the present work.

Lastly, one caveat applies. This paper is concerned with design-efficient computing of a quite general class of estimators. Generality will mean that many different estimators can be fitted to the data obtaining numerical estimates. Advances in computing power have made most of these computationally very cheap, hence a conservative "fit-them-all" strategy is feasible (although conservativeness will come at the expense of test power: see the observations at the beginning of Section 6). It must nevertheless be borne in mind that computability does not by any means guarantee statistical soundness, and that the hypotheses under which a covariance estimator is consistent and has desirable properties in finite samples are usually a subset of those under which it is actually computable.

[13] Petersen also reports Fama-MacBeth estimates. As observed in Section 1, these are nothing else but a mean groups estimator where means are taken over time instead of, as is customary in panel time series econometrics, over individual observations. Therefore this last part of Petersen's results can be replicated by swapping indices in the **plm** function `pmg`, as in the following statement: `coeftest(pmg(y ~ x, data = petersen, index = c("year", "firmid")))`.

Acknowledgments

My work has benefited greatly, at different stages, from discussions with: Liviu Andronic; Yves Croissant and Kevin Tappe, my coauthors in **plm**; Achim Zeileis, who originally devised the object-oriented framework for robust inference (Zeileis 2004, 2006); and Mahmood Arai, who provided the original implementation of panel (double-)clustered standard errors in R (Arai 2009). Despite many differences in the software approach, this implementation has been inspired by his work. Useful comments and suggestions from John Driscoll, Harry Kelejian and Douglas Miller are also gratefully acknowledged. Prof. Ron Smith is thanked for the `Parity` data.

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Affiliation:

Giovanni Millo
Group Insurance Research, Generali SpA
and
DEAMS, University of Trieste
Via Machiavelli 3
34132 Trieste, Italy
Telephone: +39/040/671184
Fax: +39/040/671160
E-mail: Giovanni.Millo@Generali.com

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COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

**MASSACHUSETTS ELECTRIC COMPANY
NANTUCKET ELECTRIC COMPANY
D/B/A NATIONAL GRID**

D.P.U 18-150

**INVESTIGATION AS TO
THE PROPRIETY OF
PROPOSED TARIFF CHANGES**

**DIRECT TESTIMONY OF
DR. MARK NEWTON LOWRY**

On behalf of

THE OFFICE OF THE ATTORNEY GENERAL

MARCH 22, 2019

DIRECT TESTIMONY OF
MARK NEWTON LOWRY
on behalf of the
THE OFFICE OF THE ATTORNEY GENERAL

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 44 East Mifflin St., Suite 601, Madison, WI 53703.

Q. What is your present occupation?

A. I am the President of Pacific Economics Group Research LLC ("PEG"), an economic consulting firm with headquarters in Madison, Wisconsin. Our primary focus is economics of energy utility regulation. Performance-based ratemaking ("PBR") and statistical research on the cost performance of energy utilities are areas of expertise. Our personnel have over sixty years of experience in these fields, which share a common foundation in economic statistics. Our work on behalf of utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity and dedication to sound research methods. Our practice is international in scope and includes numerous projects in Canada. The Ontario Energy Board ("OEB") is a longstanding client that we have helped to become a world PBR leader.

Q. Please summarize your professional experience.

A: I have over thirty years of experience as an industry economist, most of which have been spent addressing energy utility issues. I have presented in testimony results of research I supervised on PBR and the productivity of energy utilities in more than 30 proceedings. My most recent study of the productivity trends of power distributors was published by Lawrence

Berkeley National Laboratory in 2017.[1] I have authored dozens of professional publications on my work and have spoken at many conferences on PBR and performance measurement.

Before joining PEG, I was a vice president at Laurits R. Christensen Associates ("LRCA"), where I prepared research and testimony on energy utility input price and productivity trends. I also spent several years as an assistant professor in an applied economics department at the main campus of the Pennsylvania State University. A copy of my resume is attached as Schedule MNL-1.

Q. Where have you previously testified?

A: I have testified on PBR and/or cost performance before regulatory commissions in Alberta, British Columbia, California, Colorado, Delaware, the District of Columbia, Georgia, Hawaii, Illinois, Kentucky, Maine, Maryland, Massachusetts, Minnesota, Missouri, Oklahoma, New Jersey, New York, Ontario, Pennsylvania, Québec, Rhode Island, Texas, Vermont, and Washington state.

Q. What is your prior experience as a witness in Massachusetts?

A: I was the witness for Boston Gas Company on productivity and PBR plan design in the first case to establish a PBR plan with an indexed attrition relief mechanism for a Massachusetts energy utility.[2] I have also testified before the Department of Public Utilities ("Department")

[1] Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric* Utilities, for Lawrence Berkeley National Laboratory, July 2017.

[2] D.P.U. 96-50, *Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges set forth in the following tariffs: M.D.P.U. Nos. 944 through 970, filed with the Department on May*

on PBR and productivity issues for Unitil.[3] I filed comments on PBR on behalf of Commonwealth Energy and worked for a coalition of Massachusetts utilities on service quality regulation. Finally, I prepared electric power distributor productivity research for NSTAR Electric that provided the basis for the Company's X factor in an early PBR plan established in settlement.[4]

Q. Please describe your educational background.

A. I attended Princeton University before earning a bachelor's degree in Ibero-American Studies and a PhD in Applied Economics from the University of Wisconsin-Madison.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Office of the Attorney General ("AGO").

Q. What is the purpose of your testimony?

17, 1996 to become effective June 1, 1996 by Boston Gas Company; and investigation of the proposal of Boston Gas Company to implement performance-based ratemaking, and a plan to exit the merchant function.

3 D.P.U. 13-90, *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges set forth in Tariffs M.D.P.U. Nos. 229 through 238, and approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on July 15, 2013, to be effective August 1, 2013.*

4 D.P.U. 05-85, *Petition of Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and NSTAR Gas Company (collectively, the "Companies") for approval by the Department of Telecommunications and Energy of (1) a Joint Motion for Approval of Settlement Agreement and (2) the Settlement Agreement entered into by the Companies with the Attorney General of Massachusetts, the Low-Income Energy Affordability Network and Associated Industries of Massachusetts.*

A. Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or "the Company") have filed a petition with the Department for an increase in the Company's base rates. The petition includes a proposal for a five-year PBR plan. The Company's proposed plan is similar to the plan the Department recently approved for NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[5] Under its proposed plan, NGrid's allowed base revenue would be escalated by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.[6]

NGrid's X factor proposal is based on index research and testimony by Dr. Mark Meitzen of LRCA. Here, LRCA used a research methodology similar to the methodology they used in D.P.U. 17-05.[7] My testimony will address the X factor issue. I evaluate the work of LRCA and discuss some general problems with the capital cost specification LRCA used. In addition, I briefly discuss problems with the National Economic Research Associates ("NERA") research which was the foundation for LRCA's study. Next, I propose an alternative X factor that is based on my company's research. An extensive report on PEG's research and X factor issues is attached as Schedule MNL-2. This report is intended to provide the Department with information on RCI design that the Department can use in this and future PBR proceedings.

[5] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[6] Exh. NG-LRK-1, at 5. The Company's PBR Proposal includes seven components: (1) an inflation factor; (2) a "productivity offset" or X-factor formula; (3) a consumer dividend; (4) a Z factor; (5) an earnings sharing mechanism; (6) a plan term; and (7) performance incentive mechanisms and scorecard metrics.

[7] Exh. NG-MEM-1; *see also*, D.P.U. 17-05, *Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism*, Exh. ES-PBRM-1.

III. X FACTOR ISSUES

A. CRITIQUE OF THE LRCA EVIDENCE

Q. Please summarize LRCA's testimony in this proceeding.

A: LRCA's study for NGrid has its origins in power distribution productivity research by NERA. The study employs a monetary approach to the measurement of capital cost called the one-hoss-shay ("OHS") method, which specifies that the quantity of capital resulting from the total value of plant additions in a given year is constant until the plant is retired at the end of its estimated average service life. LRCA's study assumes a 33-year average service life. I have criticized the NERA/LRCA approach to measuring capital cost in several Canadian proceedings.[8]

Using data for the fifteen-year 2002-2016 period, LRCA reported a -0.13% total factor productivity ("TFP") trend for the U.S. power distribution industry and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials, a common practice in Massachusetts regulation. The sum of the resultant -0.95% productivity differential and -0.77% input price differential is **-1.72%**, which LRCA and NGrid have proposed as the base X factor. To this, NGrid proposes to add a 0.40% consumer dividend in years when inflation exceeds 2%. The 0.40% value is based on statistical benchmarking work by Dr. Lawrence Kaufmann of Kaufmann Consulting.

Q. Why did LRCA use the productivity research methods of another consultant?

[8] *See, e.g.*, Alberta Utilities Commission Proceedings 566 and 20414, and Ontario Energy Board Cases EB-2016-0152 and EB-2017-0307.

A. In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare a productivity study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. NERA's study of the productivity trends of U.S. power distributors featured a long sample period starting in 1973, and NERA advocated for an X factor based on results for the *full* sample period. Costs of several customer services were excluded from NERA's study since these services are not provided by Alberta distributors. Another unusual feature of NERA's study was the negative total factor productivity ("TFP") trend of distributors after 2000. This finding runs counter to the results that PEG obtains with methods that we have used in past studies for Massachusetts utilities.

Rather than undertake original productivity research, some utility witnesses in this proceeding embraced the results of NERA's study, but only for the period after 2000. The AUC rejected the recommendations of utility witnesses for negative X factors. Instead, AUC chose a base productivity trend of 0.96% based on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify.[9] The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study, with some modifications, rather than undertaking original studies.[10] Both consultancies based their X factor recommendations on results since 2000. LRCA argued that index research for X factor calibration should be "forward looking" and based on results for a national sample. The witness for LRCA, Dr. Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC

[9] Alberta Utilities Commission, Proceeding 20414.

[10] Alberta Utilities Commission, Proceeding 20414.

once again rejected the recommendations of the utility witnesses and instead approved an X factor of 0.30%. This decision was informed by PEG evidence of a TFP trend of 0.43% for the full sample of U.S. electric power distributors using an alternative capital cost specification.

Q. Has the productivity trend of U.S. power distributors been considered in subsequent PBR proceedings?

A. Yes. NERA subsequently presented an updated version of its power distribution productivity study in Ontario testimony to establish a PBR plan for two merging gas utilities. NERA and the OEB's consultant (PEG) both recommended a 0% base TFP trend for these utilities, which was ultimately approved by the Board.

Even though LRCA did not prevail on the X factor issue in Alberta, Eversource retained them to prepare index research for Eversource's PBR application in D.P.U. 17-05. In its study for Eversource, LRCA's methods remained quite similar to that of NERA. One notable change was LRCA's use of the number of customers as the output index. However, LRCA, like NERA, excluded costs of customer services and administrative and general tasks even though these costs are incurred by Eversource and were included by NERA in earlier research and testimony for Central Maine Power.[11] LRCA also retained NERA's capital cost methods. In addition to a substantially negative productivity differential, LRCA computed a substantially negative input price differential. The Department utilized LRCA's research in D.P.U. 17-05 and sanctioned LRCA's use of OHS but approved a lower X factor than LRCA

[11] Maine Public Utilities Commission, Docket 1999-00666.

recommended.

Recently, in a Québec proceeding to design an RCI for Hydro-Québec Distribution, the Régie de l'énergie considered the X factor issue.[12] PEG was a witness in this proceeding for industrial intervenors. With full knowledge of the Department's decision in D.P.U. 17-05 and of PEG's critique of the NERA/LRCA methodology, the Régie chose a 0.30% base productivity trend.

Q. What is your assessment of LRCA's X factor evidence for NGrid?

A. I have serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, I believe that LRCA, like NERA, used the OHS approach to measuring capital cost incorrectly. The benchmark year adjustment is wrong, and the assumed average service life of distribution assets is too low. Results are very sensitive to the assumed average service life. The average service lives of distribution assets have been rising for years and a 36-year assumption is more realistic. LRCA's input price research is even more problematic than its productivity research. Taken together, LRCA's errors materially suppress the indicated X factor in the Company's favor.

Q. Please explain your reservations about LRCA's input price research.

A. The capital price index that LRCA uses includes capital gains because plant is valued in replacement dollars. This matters because an unusual run-up in electric power distribution

[12] Québec Régie de l'énergie, R-4011-2017.

construction costs, due in part to rising copper prices, occurred during these years that is unlikely to be repeated in the next five years. LRCA's input price index captured this run-up but not the offsetting capital gains. The problem was compounded by LRCA's relatively short sample period. LRCA's treatment of the input price differential runs counter to their stated goal of conducting a forward-looking study. In their recent Ontario testimony, NERA calculated an input price differential using data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[13]

Q. Have you tested the sensitivity of LRCA's results to the problems you discuss?

A. Yes. PEG used LRCA's data but then incorporated an improved OHS specification using a 36 year average service life and a more appropriate input price index. We found that the TFP trends of U.S. power distributors averaged 0.30% from 2003 to 2016 and that the input price trend was only 2.17%. The resulting -0.52% productivity differential and 0.56% input price differential sum to a 0.04% base X factor. The analogous results for Northeastern distributors are a -0.33% TFP trend, a -1.15% productivity differential, and a 0.51% input price differential. These sum to a -0.64% base X factor.

Q. Are you comfortable with LRCA's use of the number of customers as the output index

[13] OEB proceeding EB-2017-0307, Exh. B, Tab 2, at 32 (November 23, 2017).

in its productivity work?

A. Not entirely. I acknowledge that the number of customers is commonly used to measure output in energy distributor productivity studies, including several studies that I have directed. The number of customers has also been used as the scale escalator in some RCI formulas. However, I explain at some length in Section 3.1 of my report (Schedule MNL-2) that, contrary to the unpersuasive representations of LRCA, the number of customers need not be used as the sole output measure in an RCI calibration study. Multidimensional scale indexes can instead be used, with weights based on econometric research on the cost impact of various candidate scale variables. Such indexes would likely assign a large weight to customer growth but might include other scale variables such as peak demand. Peak demand rose more rapidly than the number of customers served for many U.S. power distributors during the last fifteen years.

Q. Do you have other concerns with LRCA's work?

A. Yes, although these problems do not significantly influence LRCA's results. Here are some examples.

- LRCA includes pensions and benefits in its study even though these are slated for tracker treatment in the NGrid plan.
- LRCA treated pension and benefit expenses as material and service costs rather than labor costs;
- Some mergers were not correctly handled; and
- The sample size is unnecessarily small. This apparently is due to LRCA's reliance on the

NERA data. The capital quantity calculations require many years of plant value data. As NGrid states in response to information request DPU-NG-13-8:

> Dr. Meitzen originally obtained the dataset from the NERA study that was submitted in Alberta. FERC only posts Form 1 data on its website back to 1994. Thus, the required capital data back to 1964 for companies not in the original NERA sample would require extensive effort to compile.[14]

B. GENERAL CONCERNS ABOUT ONE HOSS SHAY

Q. Please discuss some of the general disadvantages of OHS.

A. In my view, the geometric decay ("GD") approach to calculating utility capital cost is a more appropriate approach than OHS for X factor calibration research. Under GD, the quantity of capital from plant additions is assumed to decline gradually over time. Capital cost trends using GD reflect depreciation in a manner similar to that resulting from the capital cost methods used in Massachusetts to calculate utility revenue requirements. This matters since the RCI is designed to adjust allowed revenue between rate cases.

The LRCA/NERA approach to OHS, in contrast, abstracts from depreciation. Even though NGrid acknowledged in response to information request AG-23-8 that assets that exhibit a OHS service flow pattern depreciate in value, neither the capital quantity index nor the capital service price reflect it.[15]

[14] Exh. DPU-NG-13-8.

[15] Exh. AG-23-8.

Here are some other general concerns I have with the OHS method:

- OHS formulas are more difficult to code, review, and understand. The sensitivity of results to the average service life assumption is one of many problems.

- Studies have found that prices in many used asset markets are inconsistent with the OHS assumption.[16]

- Many electric power distributor assets do not deliver a constant flow of services. Even if they did, the OHS specification of a constant service flow does not make sense for heterogeneous groups of assets with varied service lives like those typically used in LRCA's study. The following quote from a capital cost manual published by the Organization of Economic Cooperation and Development explains this point:

> In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[17]

16 For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

17 OECD, *Measuring Capital OECD Manual 2009,* Second Edition, at 12.

For these and other reasons, the OHS approach to measuring capital cost is less widely used than GD in productivity studies.

Q. Which approach to measuring capital cost is more widely used in X factor calibration studies?

A. To date, the GD approach has been most widely used in studies of this kind. For example, it is frequently used today in productivity and other statistical cost research by consultants to Ontario energy utilities. GD was also used in the great majority of LRCA's productivity studies before Dr. Meitzen started testifying for power distributors. Dr. Meitzen himself has used GD in numerous productivity studies that he prepared for telecommunications utilities and has enumerated several advantages of GD in reports that he authored. For example, this quote supporting GD, from a report Dr. Meitzen coauthored for the Peruvian telecom regulator OSIPTEL, reprises several of the points that I have already made:

> Productivity studies that are based on net stocks of capital generally employ this [geometric decay] assumption, since their net stocks are based on straight-line depreciation assumptions. The geometric pattern is based on the assumption that the productivity of an asset decreases at a constant percentage rate… Numerous productivity studies have employed this assumption, including our previous studies of the U.S. telephone industry. Hulten also notes that most empirical studies of depreciation support the use of the geometric function over the one-hoss shay or straight-line function.
>
> There are two sources for the decline in the efficiency of an asset as it ages. First, the asset may produce fewer services as it ages. Second, an asset may require more labor or materials (e.g., more maintenance) to provide the same level of services. For a cohort of assets (i.e., assets of the same asset class and the same vintage) there is a third source of efficiency decline, namely the retirement of assets. Retirement of a cohort of assets will generally occur over a number of years. As individual assets are removed from production, their contribution to the cohort will also be removed, and the overall productivity of the cohort will be reduced.[18]

[18] L. R. Christensen, M. Meitzen, P. E. Schoech, L. D. Kirsch, C. A. Herrera, and S. M. Schroeder *Price Cap Design and X Factor Estimation for Peruvian Telecommunications Regulation*, Report to OSIPTEL, May 1999, p. 68.

Q. If GD makes sense for telecommunications, how does Dr. Meitzen defend his use of the OHS method in his three power distribution productivity studies?

A. Dr. Meitzen claims in response to information request AG-23-3(c) that rapid technological change in telecommunications has caused some assets to be retired prematurely, even if they were previously yielding a constant service flow.[19]

Q. Does this make sense?

A. This is one argument for using GD in telecommunications productivity research. However, Dr. Meitzen enumerates several others. A substantial part of the business of local telecommunications exchange carriers consists of wires and poles. Moreover, technological obsolescence is sometimes observed in the business of a power distributor as well. For example, there has been rapid change in the last decade in technologies for metering, billing, pricing, and customer services. New smart grid technologies are frequently discussed in the trade press and considered for use in Massachusetts.

I should also note that many of the other arguments that Dr. Meitzen made in support of GD in the OSIPTEL report also apply to power distributors. For example, the service lives in a cohort of annual distribution plant additions are varied. Moreover, the cost of maintaining some distribution assets rises as they age. NGrid stated this in response to information request AG-15-3(f):

> The question asks whether keeping distribution plant in "good working order …" tends to require increasing *real* maintenance costs. It is not discernible whether the question intended to distinguish *real* from *nominal* expenditures. However, for assets that require regular maintenance, the costs associated with

[19] Exh. AG-23-3(c).

> keeping the plant in good working order tend to increase over the life of the asset, until it is retired. National Grid's experience, as shared with the sponsor, is that maintenance costs can increase as assets age for some specific assets.[20]

C. ORIGINAL PEG RESEARCH

Q. Have you undertaken an independent indexing study for the AGO using PEG's preferred methods and data?

A. Yes. To provide the Department with better information, PEG used a larger sample of distributors than LRCA and a longer sample period, which included 2017, the most recent year for which data are currently available. PEG calculated candidate base X factors using two alternative methods: GD and the Kahn Method. Using the GD approach to capital cost, the TFP growth of all utilities in our sample averaged 0.33%, the productivity differential was -0.65%, and the input price differential was -0.06%. The analogous results for Northeastern distributors are a 0.36% TFP trend, a -0.62% productivity differential, and a -0.12% input price differential.

Q. Please explain the Kahn Method.

A. This method for setting X factors was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. The Kahn method has been used several times by the FERC to set the X factors in PBR plans for interstate oil pipelines. It is easy to use and employs a traditional approach to calculating capital cost. The X factor resulting from such a calculation reflects the input price and productivity differentials of utilities without having to calculate them.

[20] Exh. AG-15-3(f).

Applying the Kahn method to NGrid, PEG calculated trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting. We then solved for the value of X, which caused the trend in distributor cost to equal the trend in a particular kind of RCI on average. The generic RCI used the gross domestic product price index ("GDP-PI") as the inflation measure. The analysis excludes costs that are likely to be addressed by trackers and riders in NGrid's plan. As discussed further in our report (Schedule MNL-2), we calculated a base X factor for NGrid using the Kahn method using national data and arrived at a value of -0.41%. The analogous result using Northeast data was -0.45%.

D. X FACTOR RECOMMENDATIONS

Q. What conclusions do you draw concerning the base X factor?

A. Our review of the assembled productivity evidence reveals the following facts:

Using PEG's upgraded OHS capital cost methodology and LRCA's data, the productivity differential for the full U.S. sample is -0.52% and the inflation differential is 0.56%. These indicate a base X factor of **0.04%.** The indicated base X factor using corrected OHS and Northeast data is **-0.64%.**

Using the GD capital cost methodology, PEG's own data, and research results for a larger sample and a longer sample period produces a productivity differential of -0.65% and an input price differential of -0.06%. This indicates a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**

The indicated base X factor using the Kahn method is **-0.41%.**

Other plan provisions should also be considered when choosing the X factor:

- The stretch factor is an important part of customer benefits from any PBR plan. A 0.40% value has been recommended for a reason: NGrid has been spending large sums on capex in recent years and its cost of service is, at least temporarily, high. The proposed 0.40% stretch factor is contingent on 2% inflation. This provision is rare in PBR plans. Productivity growth does not vary with inflation. Inflation has been sluggish in recent years and this may continue.

- NGrid is requesting tracker treatment for certain grid modernization and electric vehicle capital expenditures ("capex") that are now and will in the future be incurred by the utilities sampled in productivity studies. These kinds of capex will be incurred by the utilities used in future X factor calibration studies. If PBR continues, there is then a danger that customers will pay twice for the same capital expenditures.

- NGrid has also asked for higher vegetation management expenses to be tracked. This is also unusual in PBR plans but may be defensible if an increase in service quality is expected.

- NGrid is not requesting a scale escalator for its RCI growth formula. However, our analysis has shown that expected customer growth is not an implicit stretch factor. Trends in other dimensions of scale are also pertinent. Peak demand growth is widely recognized to be a major driver of power distribution cost, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, and assuming that the RCI does not include an explicit scale escalator as proposed, PEG recommends a base X factor of **-0.60%** for NGrid.

Further, we believe that the Department should recognize that there are a range of methodologies that warrant consideration when choosing X factors. The 0.40% additional stretch factor should not be contingent on inflation. Therefore, NGrid's total X factor should then be -0.20%.

Q. Does this conclude your direct testimony?

A. Yes.

RESUME OF
MARK NEWTON LOWRY

March 2019

Home Address 1511 Sumac Drive
Madison, WI 53705
(608) 233-4822

Business Address 44 E. Mifflin St., Suite 601
Madison, WI 53703
(608) 257-1522 Ext. 23

Date of Birth August 7, 1952

Education High School: Hawken School, Gates Mills, Ohio, 1970
BA: Ibero-American Studies, University of Wisconsin-Madison, May 1977
Ph.D.: Applied Economics, University of Wisconsin-Madison, May 1984

Relevant Work Experience, Primary Positions

Present Position **President, Pacific Economics Group Research LLC, Madison WI**

Chief executive and sole proprietor of a consulting firm in the field of utility economics. Leads internationally recognized practice performance-based regulation and utility performance research. Other research specialties include: utility industry restructuring, codes of competitive conduct, markets for oil and gas, and commodity storage. Duties include project management and expert witness testimony.

October 1998-February 2009 **Partner, Pacific Economics Group, Madison, WI**

Managed PEG's Madison office. Developed internationally recognized practice in the field of statistical cost research for energy utility benchmarking and Altreg. Principal investigator and expert witness on numerous projects.

January 1993-October 1998 **Vice President**
January 1989-December 1992 **Senior Economist, Christensen Associates, Madison, WI**

Directed the company's Regulatory Strategy group. Participated in all Christensen Associates testimony on energy utility Altreg and benchmarking.

Aug. 1984-Dec. 1988 **Assistant Professor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Responsibilities included research and graduate and undergraduate teaching and advising. Courses taught: Min Ec 387 (Introduction to Mineral Economics); 390 (Mineral Market Modeling); 484 (Political Economy of Energy and the Environment) and 506 (Applied Econometrics). Research specialty: role of storage in commodity markets.

August 1983-July 1984 **Instructor, Department of Mineral Economics, The Pennsylvania State University, University Park, PA**

Taught courses in Mineral Economics (noted above) while completing Ph.D. thesis.

April 1982-August 1983 **Research Assistant to Dr. Peter Helmberger, Department of Agricultural and Resource Economics, University of Wisconsin-Madison**

Dissertation research on the role of speculative storage in markets for field crops. Work included the development of a quarterly econometric model of the U.S. soybean market.

March 1981-March 1982 **Natural Gas Industry Analyst, Madison Consulting Group, Madison, Wisconsin**

Research under Dr. Charles Cicchetti in two areas:

– Impact of the Natural Gas Policy Act on the production and average wellhead price of natural gas in the United States. An original model was developed for forecasting these variables through 1985.

– Research supporting litigation testimony in an antitrust suit involving natural gas producers and pipelines in the San Juan Basin of New Mexico.

Relevant Work Experience, Visiting Positions:

May-August 1985 **Professeur Visiteur, Centre for International Business Studies, Ecole des Hautes Etudes Commerciales, Montreal, Quebec.**

Research on the behavior of inventories in metal markets.

Major Consulting Projects

1. Competition in the Natural Gas Market of the San Juan Basin. Public Service of New Mexico, 1981.
2. Impact of the Natural Gas Policy Act on U.S. Production and Wellhead Prices. New England Fuel Institute, 1981
3. Modeling Customer Response to Curtailable Service Programs. Electric Power Research Institute, 1989.
4. Customer Response to Interruptible Service Programs. Southern California Edison, 1989.
5. Measuring Load Relief from Interruptible Services. New England Electric Power Service, 1989.
6. Design of Time-of-Use Rates for Residential Customers. Iowa Power, 1989.
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30. Productivity Research and PBR Plan Design for Bundled Power Service and Gas Distribution. Public Service Electric & Gas, 1995.
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34. Productivity and PBR Plan Design Research and Testimony for a Natural Gas Distributor Operating under Decoupling. Southern California Gas, 1995.
35. Productivity Research and Testimony for a Natural Gas Distributor. NMGas, 1995.
36. Speech on PBR for Electric Utilities. Hawaiian Electric, 1995.
37. Development of a Price Cap Plan for a Midwest Gas Distributor. Illinois Power, 1996.
38. Stranded Cost Recovery and Power Distribution PBR for a Restructuring U.S. Electric Utility. Delmarva Power, 1996.
39. Productivity and Benchmarking Research and Testimony for a Natural Gas Distributor. Boston Gas, 1996.
40. Consultation on the Design and Implementation of Price Cap Plans for Natural Gas Production, Transmission, and Distribution. Comision Reguladora de Energia (Mexico), 1996.
41. Power Distribution Benchmarking for a PJM Utility. Delmarva Power, 1996.
42. Testimony on PBR for Power Distribution. Commonwealth Energy System, 1996.
43. PBR Plan Design for Bundled Power Services. Hawaiian Electric, 1996
44. Design of Geographic Zones for Privatized Natural Gas Distributors. Comision Reguladora de Energia (Mexico), 1996.
45. Statistical Benchmarking for Bundled Power Service. Pennsylvania Power & Light, 1996.
46. Presentation on Performance-Based Regulation for a Natural Gas Distributor, Northwestern Utilities, 1996.
47. Productivity Research and PBR Plan Design (including Service Quality) and Testimony for a Gas Distributor under Decoupling. BC Gas, 1997.
48. Price Cap Plan Design for Power Distribution Services. Comisión de Regulación de Energía y Gas (Colombia), 1997.
49. White Paper on Utility Brand Name Policy. Edison Electric Institute, 1997.
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51. Statistical Benchmarking for Bundled Power Service and Testimony. Pacific Gas & Electric, 1997.
52. Review of a Power Purchase Contract Dispute. City of St. Cloud, MN, 1997.
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58. Research and Testimony on Gas and Electric Power Distribution TFP. San Diego Gas & Electric, 1997-98.
59. Cost Structure of Power Distribution. Edison Electric Institute, 1998.
60. Cross-Subsidization Measures for Restructuring Electric Utilities. Edison Electric Institute, 1998.
61. Testimony on Brand Names. Edison Electric Institute, 1998.
62. Research and Testimony on Economies of Scale in Power Supply. Hawaiian Electric Company, 1998.
63. Research and Testimony on Productivity and PBR Plan Design for Bundled Power Service. Hawaiian Electric and Hawaiian Electric Light & Maui Electric, 1998-99.
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65. Statistical Benchmarking for Power Distribution. Victorian distribution business, 1998-9.
66. Testimony on Functional Separation of Power Generation and Delivery in Illinois. Edison Electric Institute, 1998.
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Energy Journal
Journal of Economic Dynamics and Control
Materials and Society

Association Memberships (active)

International Association for Energy Economics
Wisconsin Public Utilities Institute

PBR Plan Design for National Grid in Massachusetts

March 22, 2019

Mark Newton Lowry, Ph.D.
President

PACIFIC ECONOMICS GROUP RESEARCH LLC

44 East Mifflin, Suite 601
Madison, Wisconsin USA 53703
608.257.1522   608.257.1540 Fax

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1. Introduction and Summary

1.1. Introduction

On November 15, 2018, National Grid USA filed an application with the Massachusetts Department of Public Utilities ("Department") concerning rates for the power distributor services of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid ("NGrid" or the "Company"). The Company's petition proposes a five-year Performance-Based Ratemaking ("PBR") plan which includes a change in base distribution rates, followed by a PBR mechanism ("PBRM") to adjust rates annually for four years.[1] The proposed plan is similar to that which the Department recently approved for power distributor services of NStar Electric Company and Western Massachusetts Electric Company, each d/b/a Eversource Energy ("Eversource").[2] If approved by the Department, NGrid's plan would allow the Company's base revenue to escalate by a revenue cap index ("RCI") with a formula that includes an inflation measure and an X factor.

The X factor is a key issue in PBR plans of this type. NGrid's X factor proposal is based on input price and productivity research and testimony by Dr. Mark Meitzen of the consulting firm Laurits R. Christensen Associates ("LRCA"). Dr. Meitzen used a research methodology like the one he employed in testimony for Eversource.[3]

NGrid is one of the largest power distributors in the Commonwealth. LRCA's research supporting the X factor approved for Eversource was controversial and vigorously contested.[4] These considerations increase the importance of a careful appraisal of NGrid's PBR proposal and supportive index research. Controversial technical work and PBR provisions should be highlighted and, where warranted, challenged to avoid undesirable precedents for the NGrid and other Massachusetts utilities in the future.

Pacific Economics Group Research ("PEG") is the leading North American consultancy in the field of energy utility input price and productivity research. PEG has consulted with regulators, utilities,

[1] Exh. NG-PBRP-1, at 50.

[2] D.P.U. 17-05, *Order Establishing Eversource's Revenue Requirement* (November 30, 2017).

[3] *See generally*, D.P.U. 17-05, Exhs. ES-PBRM-1; ES-PBRM-Rebuttal-1.

[4] *See, e.g.*, D.P.U. 17-05, Exhs. AG/DED-1; ES-AG/DED-Surrebuttal-1.

consumer groups and government agencies; giving PEG a reputation for objectivity and advocacy for sound regulations. Our personnel have testified several times for utilities in Massachusetts and other New England states. The Attorney General of Massachusetts ("AGO") has retained PEG to prepare analysis and commentary on LRCA's research and testimony and certain aspects of NGrid's PBR proposal.

Following a summary of PEG's findings, Section 2 of this report reviews pertinent background information regarding NGrid's proposed PBR plan. In Section 3, the nature of productivity research and its role in RCI design are discussed. In Section 4, PEG critiques LRCA's methodologies and findings using alternative methods. Section 5 presents results of original X factor calibration research that PEG prepared for the AGO. Finally, Section 6 discusses the stretch factor and PEG's X factor recommendations. Appendices address some of the more technical issues raised in the report in more detail.

1.2. Summary

X Factor

PEG has serious concerns about some of the methods used in LRCA's research for NGrid. Most importantly, we believe that LRCA has used the one-hoss-shay ("OHS") approach to measuring capital cost incorrectly and that their errors materially suppress the indicated X factor in the Company's favor. With an improved OHS approach and LRCA's data, PEG finds using national data that the total factor productivity ("TFP") trends of U.S. power distributors averaged 0.30% from 2003 to 2016. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor would be **0.04%** and not the **-1.72%** that LRCA reports. Further, the OHS method has general disadvantages in X factor calibration, which are discussed below.

PEG also calculated a base X factor using two alternative methods: geometric decay ("GD") and the Kahn Method. Our research used a larger sample of distributors than LRCA did and a longer sample period that included 2017. Using GD, the TFP growth of all utilities in the national sample averaged 0.33%. The productivity differential was -0.65% and the input price differential was -0.06%. These findings indicate a base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.** The base X factor using the Kahn method and national data was **-0.41%.** The base X factor using the Kahn method and Northeast data was **-0.45**%. The stretch factor would be operative only if inflation exceeds 2%.

Other plan provisions also merit consideration in the choice of an X factor. The stretch factor is contingent on inflation exceeding 2%. An uptick in vegetation management expenses would be tracked. A tracker treatment is proposed for certain grid modernization and electric vehicle capital expenditures ("capex"). These kinds of capex will raise the cost of U.S. distributors in productivity studies used to set X factors.

Based on the assembled evidence and assuming that the RCI as proposed does not have an explicit scale escalator, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The stretch factor would apply whether or not inflation exceeded 2%.

2. Background

NGrid's proposed PBR plan is essentially a multi-year rate plan ("MRP") that includes an RCI for allowed revenue escalation and a performance metric system. The term of the plan would be five years. Initial rates would be established in a general rate case. Allowed base revenue would then be escalated for four years by an RCI with an inflation minus a productivity offset (i.e., I – X) formula. A decoupling mechanism would ensure that actual revenue would track allowed revenue closely.

The RCI formula would feature the gross domestic product price index ("GDP-PI") as the inflation measure. The proposed -1.32% X factor would be the sum of a -1.72% base productivity offset and a 0.40% consumer dividend would be added if inflation exceeds 2%. The base productivity offset would be the sum of a productivity differential and an inflation differential. Thus, the input price and productivity trends of power distributors are both issues in this proceeding.

Some costs would be scheduled for tracker treatment. These would include pension and benefit and demand-side management ("DSM") expenses. Supplemental revenue would be available for an electric vehicle infrastructure program and grid modernization. A Z factor provision would adjust revenue for unforeseeable, exogenous cost changes.[5]

The grid modernization tracker, as proposed, addresses the cost of investments pre-approved by the DPU in grid modernization plan proceedings and the Company's proposed storage program. A grid modernization program was approved in 2018 to allow NGrid to invest in various technologies including Volt/Var Optimization, advanced distribution automation, and feeder monitors over a 3-year term. The Company is required to file a new grid modernization plan during the MRP term. It is unclear how much grid modernization capex will be approved for tracking during the latter years of the term. The storage program has been proposed in this proceeding. If approved, the Company would build several storage projects.

NGrid has another cost tracker that addresses the capital and operation and maintenance ("O&M") costs associated with EV deployment. The Company received approval of Phase 1 of the deployment in 2018 and has proposed Phase 2 of deployment in this proceeding. For Phase 2, the

[5] Exh. NG-LRK-1, at 7.

Company proposes to deploy charging infrastructure, provide rebates and discounts to customers, provide fleet advisory services, market and evaluation the plan, and undertake research and development.

The Company also proposes to continue to rely on an existing vegetation management tracker to fund the incremental O&M costs of its enhanced vegetation management pilot. The current program was approved in D.P.U. 17-92 for a 4-year period beginning April 1, 2019.[6] The existing program allows the Company to perform targeted vegetation management of worst performing circuits with enhanced clearances including condition assessment and outreach with affected individuals. In the current proceeding, the Company has proposed to expand the vegetation management provision to address the incremental O&M costs of switching to a four-year pruning cycle, as well as to expand the removal of ash trees damaged by the emerald ash borer and oak trees damaged by gypsy moths.

The Company has also proposed to continue its storm fund replenishment tracker to address incremental O&M costs of major storms. This fund allows NGrid to receive funding, net of a deductible per storm, to address major storm costs. To help stabilize the fund, costs of extreme storms would continue to be addressed separately.

The Company has also proposed to include a Z factor, referred to as an exogenous cost adjustment. In order to qualify as an exogenous cost, an event must be beyond the Company's control; arise from a change in accounting requirements, regulatory, judicial, or legislative directives or enactments; be unique to the electric distribution industry rather than the general economy; and exceed a materiality threshold. The materiality threshold would be $3 million per event for 2020, and the Company has proposed to escalate the threshold for each year of the plan by the growth in GDP-PI. Two specific types of events would be explicitly eligible for exogenous cost treatment: severe storms and any excise tax on high-cost employer medical insurance plans under the Patient Protection and Affordable Care Act.

[6] D.P.U. 17-92, *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval for an Enhanced Vegetation Management Pilot Program and the recovery of associated costs through an Enhanced Vegetation Management Pilot Program Provision, M.D.P.U. No. 1343* (August 13, 2018).

A tiered earnings sharing mechanism ("ESM") would share surplus earnings above a 200 basis point deadband above the allowed return of equity.[7] An efficiency carryover mechanism was considered by NGrid but not proposed.

The performance metric system would include performance incentive mechanisms ("PIMs") for peak load reduction, transportation electrification, EV program cost containment, and "customer ease" as well as the PIMs that are already operational for service quality and DSM. Three new "scorecard metrics" without PIMs are also proposed.[8] The proposal also encompasses a Climate Mitigation and Adaptation Plan.[9]

[7] Exh. NG-LRK-1, at 7.

[8] Exh. NG-LRK-1, at 8-10.

[9] Exh. NG-NG-PBRP-1, at 104-105.

3. Principles for X Factor Calibration

3.1. Productivity Research and its Use in Regulation

This section of the report considers some technical and theoretical issues that arise in input price and productivity research to support X factor choices in PBR plans. Issues are emphasized which arise in our appraisal of NGrid's PBR proposal and the input price and productivity research presented by LRCA.

Productivity Indexes

A productivity index measures the efficiency with which firms use production inputs to achieve certain outputs. The growth in a productivity index is the difference between the growth in an output index ("Outputs") and the growth in an input quantity index ("Inputs").

growth Productivity = growth Outputs – growth Inputs. [1]

That is, productivity grows when the output index rises more rapidly than the input index.

Productivity can be volatile but usually has a rising trend in the longer run. The volatility is typically due to fluctuations in outputs and/or the uneven timing of expenditures. The productivity growth of individual companies tends to be more volatile than the average productivity growth of a group of companies.

The scope of a productivity index depends on the array of inputs addressed by the input quantity index. Partial factor productivity indexes measure productivity in the use of certain inputs such as capital or labor. A *multifactor* productivity index measures productivity in the use of multiple inputs. In Massachusetts, these are usually called *total factor* productivity indexes even though such indexes rarely address the productivity of all inputs.

The output (quantity) index of a firm summarizes growth in its outputs. If the index is multidimensional, then the growth in each output dimension which is itemized is measured by a subindex, and growth in the summary index is a weighted average of the growth in the subindices.

In designing an output index, choices concerning subindices and weights should depend on the way the index is to be used. One possible objective is to measure the impact of output growth on *revenue*. In that event, the subindices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.[10] A productivity index calculated using a revenue-weighted output index ("*Outputs*^{R}") will be denoted as *Productivity*^{R}.

$$\textit{growth Productivity}^R = \textit{growth Outputs}^R - \textit{growth Inputs}. \qquad [2a]$$

Another possible objective of output research is to measure the impact of output growth on *cost.* In that event, the index should be constructed from one or more output variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts. The sensitivity of cost to a small change in the value of a business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the operations of utilities. Such estimates provide the basis for elasticity-weighted output indexes.[11] A productivity index calculated using a cost-based output index ("*Outputs*^{C}") will be denoted as *Productivity*^{C}.

$$\textit{growth Productivity}^C = \textit{growth Outputs}^C - \textit{growth Inputs}. \qquad [2b]$$

This may fairly be described as a "cost efficiency index."

Sources of Productivity Growth

Economists have considered the drivers of productivity growth using mathematical theory and empirical methods.[12] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important productivity growth driver is economies of scale. These economies are realized in the longer run if cost tends to grow less rapidly than operating scale. Incremental scale

[10] This approach to output quantity indexation is due to the French engineer and economist Francois Divisia (1889-1964).

[11] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

[12] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

economies (and thus productivity growth) will typically be lower the slower is output growth.[13]

A third driver of productivity growth is X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher its current inefficiency level is.

Productivity growth is also affected by changes in the miscellaneous business conditions, other than input price inflation and output growth, which affect cost. A good example for a power distributor is forestation. In a suburb or rural area where forestation is increasing, rising vegetation management expenses due to maturing trees will cause operation and maintenance ("O&M") and total factor productivity growth to slow.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the initial capital stock is large relative to the need to refurbish or replace aging plant. If a utility requires unusually high replacement capex, capital productivity growth can be unusually slow. On the other hand, productivity growth tends to accelerate in the aftermath of unusually high capex as the surge capital depreciates, thereby reducing the rate of return component of capital cost.

A TFP index with a *revenue*-weighted output index ("TFP^R") has an important driver that doesn't affect a cost efficiency index. This is true since:

$$\begin{aligned} \text{growth } TFP^R &= \text{growth } Outputs^R - \text{growth } Inputs + (\text{growth } Outputs^C - \text{growth } Outputs^C) \\ &= (\text{growth } Outputs^C - \text{growth } Inputs) + (\text{growth } Outputs^R - \text{growth } Outputs^C) \\ &= \text{growth } MFP^C + (\text{growth } Outputs^R - \text{growth } Outputs^C). \end{aligned} \tag{3}$$

Relation [3] shows that the growth in TFP^R can be decomposed into the trend in a cost efficiency index and an "output differential" that measures the difference between the impact that trends in outputs have on revenue and cost.

[13] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow.

The output differential is sensitive to changes in external business conditions such as those that drive system use. For example, the revenue of a power distributor may depend chiefly on system use, while cost depends chiefly on system capacity. In that event, mild weather can depress revenue more than cost, reducing the output differential and slowing growth in TFP^R and earnings.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of RCIs. Consider the following basic result of cost theory:

$$\textit{growth Cost} = \textit{growth Input Prices} - \textit{growth Productivity}^C + \textit{growth Scale}^C.\text{[14]} \quad [4]$$

The growth in the cost of a company is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index. This result provides the basis for a revenue cap escalator of general form:

$$\textit{growth Allowed Revenue}^{Utility} = \textit{growth Input Prices} - X + \textit{growth Scale}^{Utility} \quad [5a]$$

where

$$X = \overline{TFP^C} + \textit{Stretch}. \quad [5b]$$

Here X, the "X factor," reflects a base productivity growth target ("$\overline{TFP^C}$") that is typically the trend in the TFP^C of the regional or national utility industry or some other peer group. Notably, a cost-based output index should be used in the supportive productivity research. Further, a "stretch factor" is often added to the formula, which slows price cap index growth in a manner that shares the financial benefits of performance improvements which are expected under the PBR plan with customers. Since the X factor often includes *Stretch* it is sometimes said that the productivity research has the goal of "calibrating" (rather than solely determining) X.

An alternative basis for an RCI can be found in index logic. It can be shown that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index:

[14] *See, e.g.*, Denny, Fuss and Waverman, *op. cit.*

growth Cost = growth Input Prices + growth Input Quantities [6]

Then,

growth Cost = growth Input Prices + growth Scale^C - (*growth Scale*^{C} – *growth Input Quantities*)

= *growth Input Prices – growth Productivity*^{C} + *growth Scale*^{C} [7]

For gas and electric power distributors, the number of customers served is a sensible scale escalator for an RCI. The customers variable typically has the highest estimated cost elasticity amongst the scale variables modelled in econometric research on distribution cost. A scale escalator that includes volumes and peak demand as output variables diminishes a utility's incentive to promote DSM. This is an argument for excluding these variables from an RCI scale escalator.

Relation [6] can then be expanded to obtain the following result:

growth Cost = growth Input Prices + growth Input Quantities + (*growth Customers - growth Customers*)

= *growth Input Prices –* (*growth Customers - growth Inputs*) *+ growth Customers*

= *growth Input Prices – growth TFP*^{N} *+ growth Customers*

where *TFP*^{N} is a TFP index that uses the number of customers to measure output. This result provides the rationale for the following revenue cap index formula

growth Revenue = growth Input Prices – X + growth Customers [8a]

where

$X = \overline{TFP}^N + Stretch.$ [8b]

An equivalent formula is:

growth Revenue – growth Customers

= *growth* (*Revenue/Customer*) = *growth Input Prices – X*. [8c]

This is sometimes called a "revenue per customer" index and, for convenience, this expression will be used to refer to RCIs which conform to either [8a] or [8c].

<u>Inflation Issues</u>

If a macroeconomic inflation index, such as GDP-PI, is used as the inflation measure in a RCI, then Relation [4] can be restated as:

$$
\begin{aligned}
\textit{growth Cost} &= \textit{growth Input Prices} - \textit{growth Productivity} + \textit{growth Scale} \\
&\qquad + \textit{growth GDPPI} - \textit{growth GDPPI} \\
&= \textit{growth GDPPI} - [\textit{growth Productivity} + (\textit{growth GDPPI - growth Input Prices})] \\
&\qquad + \textit{growth Scale}. \qquad [9]
\end{aligned}
$$

Relation [9] shows that cost growth depends on GDP-PI inflation, growth in operating scale and productivity, and on the difference between GDP-PI and utility input price inflation. The difference between GDP-PI and utility input price inflation may be termed the “inflation differential.”

The GDP-PI is the U.S. government’s featured index of inflation in the prices of the economy’s final goods and services.[15] It can then be shown that the trend in the GDP-PI is well-approximated by the difference between the trends in the economy’s input price and (multifactor) productivity indexes.

$$\textit{growth GDPPI} = \textit{growth Input Prices}^{Economy} - \textit{growth Productivity}^{Economy}. \qquad [10]$$

The formula for the X factor can then be restated as:

$$X = [(\overline{TFP}^{C} - \overline{TFP}^{Economy}) + (\overline{\textit{Input Prices}}^{Economy} - \overline{\textit{Input Prices}}^{Industry})]. \qquad [11]$$

Here, the first term in parentheses is called the “productivity differential.” It is the difference between the TFP trends of the industry and the economy. The second term in parentheses is called the “input price differential.” It is the difference between the input price trends of the economy and the industry.

Relation [11] is notable because it has been the basis for the design of several approved X factors in PBR. This approach has been especially popular in New England regulation.[16]

3.2. Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost specification is critical in research on the productivity trends of energy distributors because the technology of these companies is capital intensive. The cost of capital (“*CK*”) includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

[15] Final goods and services include consumer products, government services, and exports.

[16] This approach has been approved in Massachusetts on several occasions. *See, e.g.*, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, and D.P.U. 17-05.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in TFP research. Capital cost decomposes into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK.^{17} \qquad [12]$$

Capital quantity indexes are constructed by deflating the value of plant additions using an asset price index and subjecting the resultant quantity estimates to a mechanistic decay specification. In research on the productivity of U.S. energy utilities, Handy Whitman utility construction cost indexes have traditionally been used for this purpose.

In rigorous statistical cost research, it is commonly assumed that a capital good provides a stream of services over some period of time (i.e., service life of the asset). The capital quantity index measures this flow, while the capital price index measures the trend in the price of a unit of capital service. The design of the capital service price index is consistent with the assumption about the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

Alternative Monetary Approaches

Several monetary methods have been established for measuring capital quantity trends. A key issue in the choice between some monetary methods is the pattern of decay in the service flow from capex in a given year. Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile. Another issue in the choice between monetary methods is whether plant is valued in historic dollars or replacement dollars. Three monetary methods have been used in X factor calibration research:

1. <u>Geometric Decay</u> ("GD"). Under the GD method, the flow of services from investments in a given year declines at a constant rate ("*d*") over time. The quantity of capital at the end of each period

[17] The growth rate of capital cost equals the sum of the growth rates of the capital price and quantity indexes.

t (“XK_t”) is related to the quantity at the end of *last* period and the quantity of gross plant *additions* (“XKA_t”) by the following “perpetual inventory” equation:

$$XKt = XK_{t-1} \bullet (1-d) + XKA_t \,. \tag{13a}$$

$$= XK_{t-1} \bullet (1-d) + \frac{VKA_t}{WKA_t}. \tag{13b}$$

Here *d* is the (constant) rate of decay in the quantity of older capital. In Relation [13b], the quantity of capital added each year is measured by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index (“*WKA*”). In research on the productivity of U.S. energy utilities a Handy Whitman Construction Cost Index is conventionally used for this purpose.

The GD method assumes a replacement (i.e., current dollar) valuation of plant. Replacement valuation differs from the historical (a.k.a. “book”) valuation used in North American utility accounting. Cost is computed net of capital gains and the capital service price reflects this.

2. One-Hoss-Shay (“OHS”). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero. This is the pattern that is typical of an incandescent light bulb. However, OHS in practice applies this constant flow assumption to plant additions for large groups of assets. The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements (“XKR_t”).

$$XK_t = XK_{t-1} + XKA_t - XKR_t. \tag{14a}$$

$$= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \tag{14b}$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the assets retired were added.

Plant is once again valued at replacement cost. Cost is computed net of capital gains and the capital service price reflects this.

3. Cost of Service (“COS”). The GD and OHS approaches for calculating capital cost use assumptions that are different from those used to calculate capital cost under traditional COS

ratemaking.[18] With both approaches, the trend in capital cost is a simulation of the trend in cost incurred for capital services in a competitive rental market. It may be argued that the derivation of an RCI using index logic (*see supra* 10-11) does not require a service price treatment of the capital price.

An alternative COS approach to measuring capital cost has been developed that decomposes capital cost into a price and quantity index using a simplified version of COS accounting. Capital cost is not intended to simulate the cost of capital services in a competitive rental market. Capital price cannot be represented as a capital service price. This approach is based on the assumptions of straight-line depreciation and historic valuation of plant. The formulae are complicated, making them more difficult to code and review.[19]

Benchmark Year Adjustments

Utilities have various methods for calculating depreciation expenses that they report to regulators. It is, therefore, desirable when calculating capital quantities using a monetary method, to rely on the reporting companies chiefly for the value of gross plant additions but to use a standardized depreciation treatment for all companies. Since some of the plant a utility owns may be 40-60 years old, it is desirable to have gross plant addition data for many years in the past.

For earlier years, the desired gross plant addition data are frequently unavailable. Consequently, it is customary to consider the value of all plant at the end of the limited-data period and then estimate the quantity of capital that it reflects using construction cost indexes from earlier years and assumptions about the historical capex pattern. The year for which this estimate is undertaken is commonly called the “benchmark year” of the capital quantity index. Since the estimate of the capital quantity in the benchmark year is inexact, it is preferable to base capital and total cost research on a sample period that begins many years after the benchmark year. Research on capital and total cost will be less accurate to the extent that this is impossible.

[18] The OHS assumptions are more markedly different.

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board’s recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

Choosing the Right Monetary Approach

The relative merits of alternative monetary approaches to measuring capital cost have been discussed at some length in PBR proceedings.[20] Based on PEG's experience in proceedings of this nature, we believe that the following considerations are particularly relevant:

1. <u>The goal of productivity research in X factor calibration is to find a just and reasonable means to adjust rates between rate applications</u>.

   Productivity studies have many uses but the best methodology for one application may not be best for another application. One use of productivity research is to measure the trend in a utility's operating efficiency. Another use is to calibrate the X factor in a price-cap or revenue-cap index.

   Rate and revenue cap indexes used in MRPs of utilities, including NGrid's proposal, are intended to adjust utility revenue between general rate cases that employ a cost of service approach to capital cost measurement. In North America, the calculation of capital cost for ratemaking typically involves an historical valuation of plant and straight-line depreciation. Absent a rise in the target rate of return, the cost of each asset shrinks over time as depreciation reduces net plant value and the return on rate base.

2. <u>OHS is not preferable to GD as the foundation for a monetary approach to capital quantity measurement</u>.

   The OHS specification is sometimes argued to better fit the service flows of individual utility assets. OHS has been used in some productivity studies filed in proceedings to determine X factors.

   Other considerations suggest that the OHS specification is disadvantageous. Here are some notable problems:

- *OHS is More Difficult to Implement Accurately than GD.* A comparison of equations [13b] and [14b] shows that implementation of GD and OHS both require a deflation of gross plant *additions*. This is straightforward since the years of the additions are known exactly. The

[20] *See, e.g.*, Exh. M2, Tab 11.1, Schedule OPG-002, Att. A of the Ontario Energy Board's recent proceeding on Ontario Power Generation Payments Amounts (EB-2016-0152).

challenge with OHS is that it also requires the deflation of plant *retirements.* The vintages of reported retirements are generally unknown to persons outside the company. OHS practitioners commonly deflate the value of retirements by the value of the construction cost index for a year in the past that reflects the assumed average service life of the assets.

Examining equation [14b], the quantity of capital in a given year will be smaller when the quantity of retirements is larger. The estimated quantity of retirements will be larger when the average service life of the assets is higher. Thus, TFP growth tends to be more rapid under the OHS approach when the average service life that is used in calculations is higher.

PEG's empirical research suggests that productivity results using OHS are quite sensitive to the average service life assumption. Seemingly reasonable service life estimates can produce negative capital quantities for some utilities. In power distribution productivity research in other proceedings, PEG found results using the OHS capital cost specification to be much more sensitive to the assumed average service life of assets than those using GD.[21,22] The sensitivity of OHS results to service life assumptions can be reduced by using plant addition and retirement data that are itemized with respect to asset type. Unfortunately, itemizations of FERC Form 1 plant addition and retirement data are not publicly available before 1994.

It should also be noted that the mathematical coding for GD is particularly intuitive and easy to implement and review. The OHS specification involves a complicated capital service price that lacks intuition. See, by way of illustration, the OHS capital input price formula stated in Exh. NG-MEM-1, at 58. The derivation of an OHS capital service price is discussed in the Appendix.

- *Prices in Many Used Asset Markets are Inconsistent with an OHS Assumption.* Alternative patterns of physical asset decay involve different patterns of asset value depreciation. Accordingly, trends in used asset prices can shed light on asset decay patterns. Several statistical studies of trends in used asset prices have revealed that they are generally not

[21] *See, e.g.*, Lowry, M.N. and Hovde, D., *PEG Reply Evidence*, Exhibit 20414-X0468, AUC Proceeding 20414, revised June 22, 2016, pp. 15-18.

[22] *See also*, Exh. M2, Tab 11.1, Sch. OPG-002, Att. A of the OEB's EB-2016-0152 proceeding for PEG's attempt to implement an established form of OHS for hydroelectric power generation.

consistent with the OHS assumption.[23] Instead, depreciation patterns, like that commensurate with GD, appear to be the norm for machinery and are generally the norm for buildings as well.[24]

- *An OHS Assumption Does Not Make Sense for Heterogeneous Groups of Assets.* In real-world productivity studies, capital quantity trends are rarely, if ever, calculated for individual assets. Instead, capital quantity trends are calculated from data on the value of plant additions (and, in the case of OHS, retirements) which encompass multiple assets of various kinds. Even if each individual asset had an OHS age/efficiency profile, the age/efficiency profile of the aggregate plant additions could be poorly approximated by OHS for several reasons:

  1. Assets of the same kind could end up having different service lives. Identical light bulbs installed by homeowners on June 1 in a given year, for instance, will burn out at different times;
  2. Different kinds of assets can have markedly different service lives; and
  3. Individual assets, in any event, frequently have components with different service lives. The tires in a motor vehicle, for example, typically need replacement several times before the wheels need to be replaced.

  Alternative capital cost specifications such as GD can provide a better approximation of the service flow of a group of assets that individually have OHS patterns or which are composites of assets with OHS patterns.

  Consistent with these remarks, the authors of a capital research manual for the Organization of Economic Cooperation and Development ("OECD") stated in the Executive Summary that:

  > In practice, cohorts of assets are considered for measurement, not single assets. Also, asset groups are never truly homogenous but combine similar types of assets. When dealing with cohorts, retirement distributions must be invoked because it is implausible that all capital goods of the same cohort retire at the same moment in time. Thus, it is not enough to reason in terms of a single asset but age efficiency and age-price profiles have to be combined with retirement

[23] For a survey of these studies see Barbara M. Fraumeni, "The Measurement of Depreciation in the U.S. National Income and Product Accounts," *Survey of Current Business*, July 1997, pp. 7-23. A recent Canadian study is John Baldwin, Huju Liu, and Marc Tanguay, "An Update on Depreciation Rates for the Canadian Productivity Accounts," *The Canadian Productivity Review*, Catalogue No. 15-206-X, January 2015.

[24] OECD, *Measuring Capital OECD Manual 2009*, Second Edition, p. 101.

> patterns to measure productive and wealth stocks and depreciation for cohorts of asset classes. An important result from the literature, dealt with at some length in the Manual is that, for a cohort of assets, the combined age-efficiency and retirement profile or the combined age-price and retirement profile often resemble a geometric pattern, i.e. a decline at a constant rate. While this may appear to be a technical point, it has major practical advantages for capital measurement. *The Manual therefore recommends the use of geometric patterns for depreciation* because they tend to be empirically supported, conceptually correct and easy to implement.[25] [italics in original]

- *Power Distributor Assets Do Not Exhibit a Constant Flow of Services.* A common sign of decline in the flow of services from an asset is a rise in the expenses to operate and maintain it. Another sign of a diminishing flow of services is a continual stream of "refurbishment" capital expenditures that do not boost volume or capacity. Utilities tend to experience rising OM&A expenses and refurbishment capex as many of their assets age.

- *The OHS Approach is Less Widely Used.* The disadvantages of the OHS method help to explain why alternative specifications are favored in productivity and capital quantity research. For example, GD is used to calculate capital quantities in the National Income and Product Accounts of the U.S. and Canada. Statistics Canada also uses GD in its MFP studies for sectors of the economy.[26] The U.S. Bureau of Labor Statistics, the Australian Bureau of Statistics, and Statistics New Zealand use hyperbolic decay, not OHS, in their sectoral MFP studies.

  GD has also been the capital cost specification most widely used in productivity studies intended for X factor calibration in the North American energy and telecommunications industries. GD is routinely used today in productivity and other statistical cost research by consultants serving Ontario electric utilities. PEG personnel have used the GD approach in most of its more than 30 productivity studies in work for diverse clients that have included Boston Gas.[27] PEG's 2017 study of power distributor productivity for Lawrence Berkeley National Laboratory also used

[25] OECD, *op. cit.*, at 12.

[26] For evidence on this see John R. Baldwin, Wulong Gu, and Beiling Yan (2007), "User Guide to Statistics Canada's Annual Multifactor Productivity Program," *Canadian Productivity Review*, Catalogue no. 15-206-XIE – No. 14., p. 41 and Statistics Canada, *The Statistics Canada Productivity Program: Concepts and Methods*, Catalogue no. 15-204, January 2001.

[27] D.P.U. 96-50.

GD.[28] Laurits R Christensen, major professor in the PhD committee of Dr. Makholm, and his colleague Dr. Mark Meitzen of LRCA used GD in virtually all of their numerous studies of telecommunications utility productivity. LRCA has to our knowledge also used GD in most of their studies over the years of *energy* utility productivity, including ones for the staff of Maine Public Utilities Commission and for Union Gas.[29] Concentric Energy Advisors used GD in their gas utility productivity study for Enbridge Gas Distribution in Ontario.[30]

[28] Lowry, M.N., Deason, J., and Makos, M. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,", Lawrence Berkeley National Laboratory, July, pp. B.19-20.

[29] *See, e.g.*, Maine PUC proceeding 2007-00215 and Hemphill, R., and Schoech, P. (1999), "An Evaluation of the Union Gas Limited Performance-Based Regulation Proposal", at 25. Dr. Schoech was listed in response to information request AG-23-3b as a member of the LRCA team for the NGrid project.

[30] James Coyne, James Simpson, and Melissa Bartos, Concentric Energy Advisors, Inc., Incentive Ratemaking Report*, Prepared for Enbridge Gas Distribution*, OEB Proceeding EB-2012-0459, Exh. A2, Tab 9, Sch. 1, p. B-11 (June 28, 2013).

4. Critique of LRCA's Productivity Research and Testimony

4.1. Background

LRCA's study for NGrid has its origins in power distribution productivity research by National Economic Research Associates ("NERA"). An early version of this study was prepared for a Central Maine Power proceeding in the late 1990s.[31] In 2010, the Alberta Utilities Commission ("AUC") retained NERA to prepare an analogous study for use in the calibration of X factors in a new PBR regime for provincial gas and electric power distributors. Since many customer services are no longer provided by distributors in Alberta, NERA removed the cost of these services from its study for the AUC as well as administrative and general ("A&G") expenses.

NERA's study featured an unusually long sample period and advocated an X factor based on results for the full sample period. An unusual feature of the study was a negative MFP trend after 2000. Power distribution studies by PEG have not shown such a trend. Rather than undertake original productivity research, some utility witnesses in this proceeding embraced results of the NERA study for the period after 2000. The AUC rejected their recommendations and instead based its 0.96% base productivity trend on NERA's results for the full sample period.

In the AUC's second generic PBR proceeding NERA did not testify. The Brattle Group and LRCA separately testified on behalf of utilities and each updated NERA's study with some modifications rather than undertaking original studies. Each consultancy based their X factor recommendations on results since 2000. LRCA argued that X factor calibration research should be "forward looking". The witness for LRCA, Dr. Mark Meitzen, had extensive experience in the field of telecommunications productivity measurement but had never testified on energy utility productivity. The AUC's 0.30% X factor recommendation was informed by utility studies using OHS but also by a study by PEG that used GD and found that the average TFP trend of U.S. power distributors was 0.43%.

NERA subsequently presented an updated version of its power distribution productivity study in testimony that supported a PBR proposal by two Ontario gas utilities. NERA and OEB's consultant

[31] Maine PUC Case 1999-00666.

recommended a 0% base productivity trend for these utilities, which was ultimately approved by the Board.

PEG was a participant in these proceedings and opposed the NERA/LRCA methodology. We argued that the marked slowdown in productivity growth around 2000 was chiefly due to NERA's use of a volumetric output index. Volumetric output indexes are sensitive to the decline in residential and commercial use per customer, as discussed in Section 3.1 above. The decline in average use growth has been real but is not very relevant to the design of RCIs for power distributors.

PEG has also been critical of NERA/LRCA's capital cost treatment. We have argued that the OHS approach to measuring capital cost has notable disadvantages and that the NERA/LRCA treatment of OHS is flawed. When the OHS treatment is upgraded, power distributor productivity growth is not negative. We argued that NERA obtained a reasonable TFP trend over their lengthy full sample period in their Alberta study because brisk growth in average use in the early years offset productivity declines in later years. In recent years, NERA-style TFP indexes have been declining due to a combination of declining average use and an inappropriate capital cost specification.

In its study for Eversource, LRCA's methodology remained quite similar to that of NERA.[32] One notable change was to use the number of customers as the output index. LRCA did not include the costs of customer services or A&G tasks even though these were costs incurred by Eversource. In addition to a substantially negative productivity differential, LRCA also computed a substantially negative input price differential. Although the Department embraced LRCA's research, including its use of OHS, the Department adopted a lower X factor than LRCA recommended.[33]

Following the Eversource decision, the X factor issue was revisited by the Régie de l'énergie in a recent Québec proceeding to design an RCI for power distribution services of Hydro-Québec.[34] PEG was a witness in this proceeding for industrial intervenors. With knowledge of both the Department's decision in D.P.U. 17-05 and PEG's critique of the NERA/LRCA methodology, the Régie acknowledged a 0.3% distribution industry productivity trend.

[32] *Compare* Exh. NG-MEM-1 *with* D.P.U. 17-05, Exh. ES-PBRM-1.

[33] D.P.U. 17-05, at 392.

[34] Québec Régie de l'énergie, R-4011-2017.

4.2. LRCA's Study for NGrid

For this proceeding, LRCA calculated the input price and productivity trends of a sample of U.S. utilities in the provision of power distributor services over the fourteen-year period 2003-2016.[35] The number of customers was used to measure output growth.

Unlike the Eversource study, expenses for A&G tasks and certain customer services were added to LRCA's NGrid study. Dr. Meitzen stated that A&G expenses were allocated on a "non-economic conceptual basis." Exh. NG-MEM-1, at 32. He stated further that his "plant-apportioned" results that allocate A&G "provides a balance between the economic measure of [TFP] and non-economic considerations of a traditional approach to the ratemaking process." Exh. NG-MEM-1, at 48.

Dr. Meitzen stressed that the X factor should be "forward looking", stating that:

> Although [the X factor] is typically determined by a productivity study that is based on historical information, [the X factor] is forward looking as it is based on those differentials that are expected to prevail over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.
>
> Exh. NG-MEM-1, at 29.

Dr. Meitzen further stated that:

> The 15 year period strikes a balance between using the most recent, relevant information for determining forward-looking changes in productivity and using a period long enough to account for short term variation in results.
>
> Exh. NG-MEM-1, at 33.

For the full national sample and "plant apportioned" cost, LRCA reported a -0.13% TFP trend and a remarkably brisk 3.50% input price trend. These results were used to calculate input price and productivity differentials. The sum of the resultant -0.95% productivity differential and -0.77% input price differential was a base X factor of **-1.72%**.[36] LRCA also produced results for a Northeast sample of utilities in the New England and mid-Atlantic states. LRCA reported a -0.69% Northeast MFP trend and a brisk 3.48% input price trend. The sum of the resultant -1.51% productivity differential and -0.75% input

[35] Exhibit NG-MEM-1 at 35.

[36] Exhibit NG-MEM-1, Figure 9, at 44.

price differential was a base X factor of **-2.27%**. LRCA recommends that the base X factor be based on the national plant-apportioned results.

4.3. Major Concerns

LRCA's methodology for measuring power distribution productivity and its discussion of RCI design are controversial. To facilitate the Department's review of the numerous and sometimes complicated issues that arise in productivity studies, below are PEG's most important concerns regarding LRCA's methodology.

Capital Specification

PEG has concerns about the OHS approach that LRCA used to measure capital cost. PEG discussed several general disadvantages of the OHS approach in Section 3.2 above. Here, we argue that LRCA's particular approach to executing OHS is flawed. Since LRCA does not itemize quantities of different kinds of distributor assets, their OHS approach is particularly sensitive to the choice of the average service life used in the conversion of the total value of distribution plant retirements each year to a quantity.

LRCA assumes a 33-year average service life.[37] The basis for this specification is presented in response to information request AG-15-4 and AG-23-4. They sought to estimate average service life by calculating a weighted average of the service lives for various distribution asset classes which utilities report periodically on FERC Form 1. The weights are the shares of each asset class in plant value.

The requisite data were readily available for this calculation only from 1994 to 2016. LRCA reports that the median average service life thus calculated rose over this period from 37.29 years in 1994 to 46.35 years in 2016.

LRCA claims that, since capital data for the 1964 to 2016 period are used in its capital quantity calculations, the average service life should be set at the value for the midpoint of this interval, which is 1990. The value of this is unavailable for 1990 but LRCA maintains that an appropriate value is the 33 years that NERA also used.

PEG has several reservations about LRCA's average service life calculations.

[37] Exhibit NG-MEM-1, pages 56 and 59.

- The average service life for 1990 is unknown. Different estimates for its value can be reasonably entertained.

  LRCA noted that there existed an upward trend in service lives to 2016 which we calculated as 0.87% per year. Using the LRCA 1994 mean value of 38.96 years and the 0.87% trend results in a value of 37.635 years in 1990. A similar calculation using the median as opposed to mean values results in a 1990 estimate of 35.84 years. A few years difference in the estimated service life may not seem material, but we have found that the OHS method is highly sensitive to the assumed service life.

- LRCA's analysis relies on utility *estimates* of average service lives which were reported to the FERC. These estimates were not always freshly calculated and rise substantially over time. It is therefore likely that they were *downward biased* as estimates of the true service lives of assets at the time that they were reported.

- The average service life at the *midpoint* of the 1972-2016 period is unlikely to be representative of retirements that occurred between 2002 and 2016.

- Average service lives going forward are clearly much higher than they were in 1990. Freezing the average service life at its estimated 1990 value seems inconsistent with LRCA's goal of calculating a forward-looking X factor.

PEG notes that the controversy over average service life when OHS is used to calculate capital cost is unfortunate and a good reason to consider results using different capital cost methods. Since the Department is nonetheless interested in results using OHS, we believe that the evidence points to an OHS value of 36 years.

The benchmark year adjustment that NERA used is another problem. We noted in Section 3 above that the computation of a capital quantity index starts with a benchmark year adjustment. PEG believes that LRCA's calculations of capital quantity indexes in its benchmark year are incorrect. OHS is sometimes characterized as a method for calculating the quantity associated with *gross* plant value. Yet LRCA deflated *net* plant values by an average of past values of a construction cost index. Consequently, PEG believes that the initial quantities of capital for each utility in LRCA's sample are understated. LRCA's method effectively removed accumulated depreciation associated with older capital twice. It was first removed when calculating net plant value and then removed again when the original value of plant is retired. When an alternative and higher average service life is used to calculate capital quantities, this understated initial capital stock can result in negative capital quantities for some utilities. Utility witnesses in Alberta used these negative capital quantities as an argument against a higher average service life.[38] A related concern is that LRCA, like NERA, did not assume a consistent 33-year average service life in making its benchmark year calculation.

Input Price Differential Calculations

NERA's input price differential calculations are also a cause for concern. As discussed in Section 3.2 above, input price differentials using implicit service price indexes are inherently awkward in X factor calibrations because assets are valued in current dollars and capital gains are considered. The 2003-2016 sample period used by LRCA was especially problematic since power distribution construction costs rose rapidly, due in part to a run-up in copper prices that was never fully reversed. This runup is illustrated in Figure 1 below, which compares GDP-PI inflation to the inflation in the producer price index for copper wire and Handy Whitman electric power distribution construction cost index.

LRCA has compounded this problem in two ways:

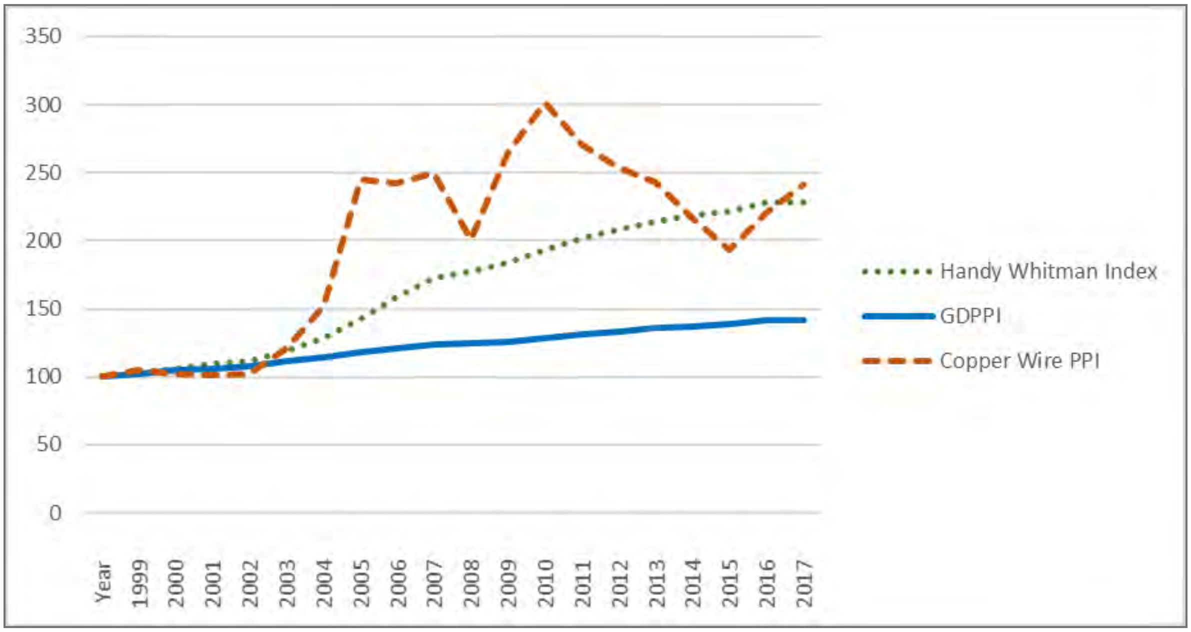
1. The sample period LRCA used is, in our opinion, too short to accurately calculate a long-term input price differential. In its recent Ontario testimony, NERA calculated an input price differential using power distribution data from the 1973-2016 period. NERA witness Dr. Jeff Makholm stated that "For input price growth, I find no statistically significant input price differential (which is the result I have always found for the US distribution data set)."[39]
2. LRCA froze the expected real rate of return in its input price index, stating that it assumed that "investor's forward looking real rate of return (cost of capital less the inflation rate) is constant through time."[40] However, LRCA allowed the construction cost index to accelerate briskly. In so doing, LRCA permitted the input price index to grow rapidly, thereby imparted a substantial negative bias to its input price differential calculations.

[38] Brattle Undertaking #4 as filed in Alberta Utilities Commission Proceeding 20414 as Exhibit 20414-X0564 and Transcript Volume 8, pp. 2808-2809 from Alberta Utilities Commission Proceeding 20414.

[39] OEB proceeding EB-2017-0307, Exhibit B, Tab 2, filed November 23, 2017, p. 32.

[40] Exh. NG-MEM-1, at 59.

Figure 1
Trends in Power Distribution Construction Costs



Sampled Companies

LRCA excluded numerous companies from its sample even though the data were available, apparently because these companies were not part of the original NERA sample. Substantially larger samples are feasible.[41]

Revenue Cap Index Design

PEG's explanation in Section 3.1 of the principles for RCI design differs from LRCA's. Particularly, we show that the scale index used to calculate TFP growth need not be the number of customers served. An elasticity-weighted scale index can be used to measure output in such research. This implies that an RCI that lacks an explicit scale escalator does not necessarily offer customer growth as an "implicit stretch factor". Trends in other scale variables can be considered. Econometric research on electric distribution cost which PEG just presented in Toronto testimony found that the number of

[41] *See, e.g.*, Lowry, M., Deason, J., Makos, M. and Schwartz, L., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, for Lawrence Berkeley National Laboratory, July 2017, p. B.13 where PEG undertook a power distributor productivity study with 86 power distributors.

customers served has an estimated cost elasticity of 0.601 but ratcheted peak demand has an estimated elasticity of 0.351.[42] The share of peak demand in the sum of the two elasticities is a sizable 37%.[43] We acknowledge, however, that the number of customers has been used in productivity studies, including studies by PEG, to calibrate the X factors of RCIs for gas and electric power distributors. These studies were sometimes done with the expectation that a revenue per customer cap would be approved.

Other Concerns

There are a number of smaller problems with LRCA's U.S. power distribution research. Taken together they have little effect on LRCA's research results but nonetheless merit mention.

- LRCA failed to correct for some mergers;
- Pension and benefit expenses are included in the study even though NGrid proposes to track the cost of these expenses;
- Pension and benefit expenses were inappropriately treated as material and service expenses. This led to more volatile and inaccurate TFP results;
- Even though pension and benefit expenses are included in the study, LRCA uses an employment cost index for salaries and wages to deflate labor cost rather than an ECI for total compensation.

Alternative Results

To illustrate some of the problems with LRCA's capital cost treatment, PEG has developed an alternative calibration exercise using LRCA's data. First, the benchmark year capital quantity calculation was revised to deflate *gross* plant value. Next, the average service life was raised from 33 to 36 years. In addition, the input price index was changed to unfreeze the expected real rate of return.

Results of this exercise are presented in Tables 1a, 1b, and 1c below. TFP growth for the full national sample averaged 0.30%. The productivity differential was -0.52% and the input price differential was 0.56%. The indicated base X factor from this research is therefore **0.04%**. The analogous result using Northeast US data is **-0.64%**. Thus, replacing the flawed NERA/LRCA approach to the OHS capital cost calculations with a more defensible treatment produces a substantially higher X factor that is less favorable to NGrid.

[42] Lowry, M.N., *IRM Design for Toronto Hydro-Electric System*, OEB, EB-2018-0165, Exhibit M1, March 20, 2019.

[43] The ratcheted peak demand of a utility is the highest value that it has yet attained.

Table 1a

PEG Modifications to LRCA Analysis – Distribution Industry

Period	Output Quantity	Input Quantity	Revenue Per Customer MFP	Input Price
2002	-	-	-	-
2003	1.28%	3.33%	-2.05%	-2.07%
2004	1.14%	-2.49%	3.63%	2.18%
2005	1.42%	1.20%	0.21%	2.01%
2006	1.04%	6.95%	-5.90%	7.10%
2007	1.07%	-4.95%	6.02%	5.90%
2008	0.64%	-0.65%	1.28%	6.50%
2009	0.08%	0.41%	-0.33%	2.88%
2010	0.38%	2.28%	-1.90%	-0.68%
2011	0.36%	1.00%	-0.64%	0.78%
2012	0.52%	1.31%	-0.78%	-3.44%
2013	0.80%	-2.86%	3.66%	6.61%
2014	0.60%	-0.27%	0.87%	2.21%
2015	0.77%	-0.31%	1.08%	0.21%
2016	0.89%	1.86%	-0.97%	0.21%
Average	**0.78%**	**0.49%**	**0.30%**	**2.17%**
Original LRCA Results				
Average	**0.78%**	**0.91%**	**-0.13%**	**3.50%**
Difference	0.00%	-0.42%	0.43%	-1.33%

Table 1b

PEG Modifications to LRCA Analysis – U.S. Economy

Year	GDPPI	MFP	Input Price
	[A]	[B]	[A] + [B]
2002	-	-	-
2003	1.87%	2.29%	4.15%
2004	2.64%	2.61%	5.25%
2005	3.05%	1.53%	4.58%
2006	3.01%	0.35%	3.36%
2007	2.66%	0.39%	3.04%
2008	1.89%	-1.19%	0.70%
2009	0.78%	-0.26%	0.52%
2010	1.16%	3.25%	4.42%
2011	2.06%	0.07%	2.13%
2012	1.91%	0.69%	2.60%
2013	1.76%	0.41%	2.16%
2014	1.86%	0.87%	2.73%
2015	1.03%	0.93%	1.96%
2016	1.08%	-0.46%	0.62%
Average	**1.91%**	**0.82%**	**2.73%**
Original LRCA Results			
Average	**1.91%**	**0.82%**	**2.73%**
Difference	0.00%	0.00%	0.00%

Table 1c

X Factor Calculations Using an Alternative OHS Capital Cost Specification

	MFP			Input Price			
Period	**Industry**	**U.S.**	**Difference**	**U.S.**	**Industry**	**Difference**	**X Factor**
	[A]	[B]	[C=A-B]	[D]	[E]	[F=D-E]	[G=C+F]
2002	-	-	-	-	-	-	-
2003	-2.05%	2.29%	-4.34%	4.15%	-2.07%	6.22%	1.89%
2004	3.63%	2.61%	1.02%	5.25%	2.18%	3.07%	4.09%
2005	0.21%	1.53%	-1.32%	4.58%	2.01%	2.57%	1.25%
2006	-5.90%	0.35%	-6.25%	3.36%	7.10%	-3.74%	-9.99%
2007	6.02%	0.39%	5.63%	3.04%	5.90%	-2.86%	2.78%
2008	1.28%	-1.19%	2.47%	0.70%	6.50%	-5.80%	-3.33%
2009	-0.33%	-0.26%	-0.07%	0.52%	2.88%	-2.36%	-2.43%
2010	-1.90%	3.25%	-5.15%	4.42%	-0.68%	5.10%	-0.06%
2011	-0.64%	0.07%	-0.71%	2.13%	0.78%	1.35%	0.64%
2012	-0.78%	0.69%	-1.47%	2.60%	-3.44%	6.04%	4.57%
2013	3.66%	0.41%	3.25%	2.16%	6.61%	-4.45%	-1.19%
2014	0.87%	0.87%	0.00%	2.73%	2.21%	0.52%	0.52%
2015	1.08%	0.93%	0.15%	1.96%	0.21%	1.75%	1.90%
2016	-0.97%	-0.46%	-0.51%	0.62%	0.21%	0.41%	-0.10%
Average	**0.30%**	**0.82%**	**-0.52%**	**2.73%**	**2.17%**	**0.56%**	**0.04%**
Original LRCA Results							
Average	**-0.13%**	**0.82%**	**-0.95%**	**2.73%**	**3.50%**	**-0.77%**	**-1.72%**
Difference	0.43%	0.00%	0.43%	0.00%	-1.33%	1.33%	1.76%

5. Productivity Research by PEG

5.1. Data

The primary source of the cost and quantity data for PEG's independent research on input price and productivity trends of U.S. power distributors is FERC Form 1. Selected FERC Form 1 data were for many years published by the U.S. Energy Information Administration (EIA).[44] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. The FERC Form 1 data used in PEG's study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report)* in later years.

Data were eligible for inclusion in the sample from all major investor-owned electric utilities in the United States that filed the FERC Form 1 in 1964 (the benchmark year for our study, described further below) and that, together with any important predecessor companies, have reported the necessary data continuously. To be included in the PEG study, the data also were required to be of good quality and plausible. Data from 80 utilities met PEG's standards and were used in our indexing work. We believe that these data are the best available for rigorous work on the productivity trends of U.S. power distributors.

Table 2 below lists the companies from which PEG's data were drawn. It can be seen that most broad regions of the United States are well represented.[45]

[44] This publication series had several titles over the years. A recent title is Financial Statistics of Major U.S. Investor-Owned Electric Utilities.

[45] Unfortunately, the requisite customer data are not available for most Texas distributors.

Table 2
Sample of Utilities Used in Productivity Model Research

Alabama Power	Madison Gas and Electric
ALLETE (Minnesota Power)	MDU Resources Group
Appalachian Power	Metropolitan Edison*
Arizona Public Service	Mississippi Power
Atlantic City Electric*	Monongahela Power
Avista	Nevada Power
Baltimore Gas and Electric	New York State Electric & Gas*
Black Hills Power	Niagara Mohawk Power*
Central Hudson Gas & Electric*	Northern Indiana Public Service
Central Maine Power*	Northern States Power - MN
Cleco Power	Ohio Edison
Cleveland Electric Illuminating	Oklahoma Gas and Electric
Commonwealth Edison	Orange and Rockland Utilities*
Connecticut Light and Power*	Pacific Gas and Electric
Consolidated Edison Company of New York*	Potomac Electric Power*
Delmarva Power & Light	Pennsylvania Electric*
DTE Electric	Pennsylvania Power*
Duke Energy Carolinas	Portland General Electric
Duke Energy Florida	PPL Electric Utilities*
Duke Energy Indiana	Public Service Company of Colorado
Duke Energy Kentucky	Public Service Company of New Hampshire*
Duke Energy Ohio	Public Service Company of Oklahoma
Duke Energy Progress	Public Service Electric and Gas*
Duquesne Light*	Puget Sound Energy
El Paso Electric	San Diego Gas & Electric
Empire District Electric	South Carolina Electric & Gas
Entergy Arkansas	Southern California Edison
Entergy Mississippi	Southern Indiana Gas and Electric
Entergy New Orleans	Southwestern Public Service
Florida Power & Light	Tampa Electric
Gulf Power	Toledo Edison
Idaho Power	Tucson Electric Power
Indiana Michigan Power	Union Electric
Indianapolis Power & Light	United Illuminating*
Jersey Central Power & Light*	Virginia Electric and Power
Kansas City Power & Light	West Penn Power*
Kansas Gas and Electric	Western Massachusetts Electric*
Kentucky Power	Wisconsin Electric Power
Kentucky Utilities	Wisconsin Power and Light
Louisville Gas and Electric	Wisconsin Public Service

Total of 80 Companies

*** Indicates a member of the Northeast Sample**

5.2. Defining Costs

The major tasks in power distribution are the local delivery of power, the reduction of its voltage, and the metering of quantities delivered. Most power is delivered to customers at the voltage at which it is consumed. This requires distributors to step down the voltage of power from the voltage at which they receive it from the transmission sector.[46] Distributors use transformers near the point of delivery to reduce voltage to the level at which it is consumed. Some also own and operate substations that receive power at subtransmission or transmission voltage.

Distributors also typically provide various customer services. In the United States, these typically include metering, meter reading, customer account, and customer service and information ("CS&I") services. Expenses reported on FERC Form 1 for CS&I services include those for utility DSM programs. These expenses will be subject to tracker treatment in National Grid's proposed plan, vary widely between utilities, and are not itemized for easy removal. We accordingly excluded all CS&I expenses from the costs of the utilities in our study.

Pension and benefit expenses are often excluded from utility cost performance studies because they are sensitive to volatile external business conditions such as stock prices. NGrid has proposed to track these expenses in its PBR plan. Consequently, unlike LRCA, PEG has excluded these expenses in this study.

The O&M expenses that PEG used in the study for U.S. utilities included those for power distribution, customer accounts, metering, and meter reading. We also included a sensible share of A&G expenses.[47] PEG excluded all reported O&M expenses incurred by sampled U.S. utilities for generation, power procurement, transmission, customer service and information, franchise fees, and gas services. The capital costs were those for distribution plant.

The total cost of power distributor services considered in the PEG study was the sum of capital costs and applicable O&M expenses. In our input price and productivity research for the AGO we employed a monetary approach to capital cost, price, and quantity measurement which featured GD.

[46] Some large industrial customers take delivery of power directly from the transmission system.

[47] This procedure is theoretically arbitrary but has little impact on results.

Capital cost was the sum of depreciation expenses and a return on net plant value less capital gains.[48] Further details of PEG's capital cost calculations are provided in Appendix Section A.1.

5.3. Input Price Indexes

Operation & Maintenance

The labor prices for U.S. utilities were escalated by regionalized Bureau of Labor Statistics ("BLS") Employment Cost Indexes for salaries and wages. Material and service ("M&S") prices were escalated by the U.S. GDP-PI.

Capital

Construction cost indexes and rates of return on capital are required in the capital cost research. PEG calculated weighted averages of rates of return for debt and equity.[49] PEG calculated for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[50] PEG used construction cost indexes from Whitman, Requardt and Associates to deflate the value of plant additions of the sampled distributors.

Summary Input Price Index

Summary input price indexes were constructed by PEG which were weighted averages of price subindexes for various inputs. Calculation of these indexes used company-specific, time-varying cost share weights for the U.S. utilities. The cost shares were calculated from FERC Form 1 O&M expense data.

[48] Capital gains are included due to the geometric decay capital cost treatment that we employ, as noted in Section 3.2 values capital at replacement cost.

[49] This calculation was made solely for the purpose of measuring productivity *trends* and does not prescribe appropriate rate of return *levels* for utilities.

[50] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

5.4. Scope of Research

PEG calculated indexes of growth in the O&M, capital, and total factor productivity of each sampled utility in the provision of power distributor services. Simple arithmetic averages of those growth rates were then calculated for all sampled companies.

5.5. Index Construction

Productivity growth was calculated for each sampled utility as the difference between the growth rates of output and input quantity trends. PEG used the growth in the total number of retail customers served as the scale metric.

In calculating input quantity trends, we broke down the applicable cost into three categories: (1) distribution plant; (2) labor; (3) M&S inputs. The cost of labor was defined for this purpose as O&M salaries and wages. The cost of M&S inputs was defined as applicable O&M expenses net of these labor costs. The growth of each total factor input quantity index was a weighted average of the growth in quantity subindexes for labor, materials and services, and power distribution plant.

5.6. Sample Period

The full sample period for which productivity results were calculated was 1997-2017.[51] The year 2017 is the latest for which the required data are currently available.

5.7. Index Results

Table 3 below summarizes our productivity research for the U.S. sample. Over the full 1997-2017 sample period, the average annual growth rate in the MFP of all sampled U.S. power distributors using GD was about +0.33%. The productivity differential was -0.65%.

Table 4 below presents PEG's input price results. The input price growth of the industry averaged 2.89% over the full sample period. The input price growth of the economy averaged 2.83%. The input price differential was -0.06%, close to zero. The sum of the input price and productivity differentials was **-0.71%.** This is the indicated base X factor from this research. The analogous base X factor using Northeast data was **-0.74%.**

[51] In other words, 1997 was the earliest year for growth rate calculations.

Table 3
Calculating the Productivity Differential – U.S.[1]

	Productivity Indexes								Productivity Differential
	U.S. Power Distributors						U.S. Private Business MFP Index[2]		
	Output Quantity		Input Quantity		Productivity				
	Index	Growth Rate	Index	Growth Rate	Index	Growth Rate [A]	Index	Growth Rate [B]	[A] - [B]
1996	100.00		100.00		100.00		100.00		
1997	101.39	1.38%	99.74	-0.26%	101.66	1.65%	101.13	1.12%	0.53%
1998	102.99	1.56%	102.08	2.33%	100.89	-0.76%	102.64	1.48%	-2.25%
1999	104.33	1.29%	104.06	1.92%	100.25	-0.63%	104.61	1.90%	-2.53%
2000	105.84	1.44%	104.61	0.52%	101.18	0.92%	106.11	1.43%	-0.51%
2001	107.94	1.97%	104.25	-0.34%	103.54	2.31%	106.59	0.45%	1.87%
2002	109.42	1.36%	104.94	0.66%	104.27	0.70%	108.76	2.02%	-1.32%
2003	110.33	0.83%	107.53	2.44%	102.60	-1.62%	111.27	2.29%	-3.90%
2004	111.66	1.20%	106.04	-1.40%	105.30	2.60%	114.21	2.61%	-0.01%
2005	113.18	1.36%	106.77	0.68%	106.01	0.67%	115.97	1.53%	-0.85%
2006	113.71	0.47%	107.64	0.81%	105.64	-0.34%	116.38	0.35%	-0.70%
2007	114.91	1.05%	110.19	2.35%	104.28	-1.30%	116.83	0.39%	-1.68%
2008	115.62	0.61%	109.74	-0.41%	105.35	1.02%	115.45	-1.19%	2.21%
2009	115.88	0.23%	108.38	-1.24%	106.92	1.47%	115.16	-0.26%	1.73%
2010	116.45	0.50%	109.48	1.01%	106.37	-0.52%	118.96	3.25%	-3.77%
2011	116.76	0.27%	109.85	0.33%	106.30	-0.07%	119.05	0.07%	-0.13%
2012	117.28	0.44%	109.92	0.07%	106.69	0.37%	119.87	0.69%	-0.32%
2013	117.92	0.55%	109.26	-0.61%	107.93	1.15%	120.36	0.41%	0.75%
2014	118.60	0.58%	110.20	0.86%	107.63	-0.28%	121.41	0.87%	-1.15%
2015	119.50	0.75%	110.30	0.09%	108.34	0.66%	122.55	0.93%	-0.27%
2016	120.61	0.92%	111.78	1.33%	107.90	-0.40%	121.98	-0.46%	0.06%
2017	121.57	0.79%	113.37	1.41%	107.23	-0.62%	122.90	0.76%	-1.38%
Average Annual Growth Rate									
1997-2017		**0.93%**		**0.60%**		**0.33%**		**0.98%**	**-0.65%**

[1]All growth rates calculated logarithmically.
[2]Source: U.S. Bureau of Labor Statistics

Table 4
Calculating the Input Price Differential – U.S.[1]

	Input Price Indexes								Input Price Differential
	United States						U.S. Power Distributor Input Prices		
	GDP-PI[2]		MFP[3]		Implied IPI				
	Index	Growth Rate [A]	Index	Growth Rate [B]	Index	Growth Rate [C=A+B]	Index	Growth Rate [D]	Growth Rate [E=C-D]
1996	100.00		100.000		100.00		100.00		
1997	101.73	1.72%	101.13	1.12%	102.88	2.84%	105.07	4.94%	-2.11%
1998	102.85	1.10%	102.64	1.48%	105.57	2.58%	108.59	3.29%	-0.71%
1999	104.33	1.42%	104.61	1.90%	109.14	3.32%	111.19	2.37%	0.95%
2000	106.68	2.23%	106.11	1.43%	113.20	3.66%	110.71	-0.44%	4.09%
2001	109.08	2.22%	106.59	0.45%	116.26	2.67%	111.30	0.53%	2.14%
2002	110.74	1.51%	108.76	2.02%	120.44	3.53%	108.76	-2.31%	5.84%
2003	112.83	1.87%	111.27	2.29%	125.55	4.15%	110.53	1.62%	2.54%
2004	115.85	2.64%	114.21	2.61%	132.32	5.25%	106.35	-3.85%	9.11%
2005	119.44	3.05%	115.97	1.53%	138.52	4.58%	99.75	-6.41%	10.99%
2006	123.09	3.01%	116.38	0.35%	143.25	3.36%	82.78	-18.65%	22.01%
2007	126.40	2.66%	116.83	0.39%	147.68	3.04%	73.68	-11.63%	14.67%
2008	128.81	1.89%	115.45	-1.19%	148.72	0.70%	71.58	-2.89%	3.60%
2009	129.82	0.78%	115.16	-0.26%	149.49	0.52%	101.57	34.99%	-34.47%
2010	131.34	1.16%	118.96	3.25%	156.24	4.42%	130.21	24.84%	-20.42%
2011	134.07	2.06%	119.05	0.07%	159.61	2.13%	151.25	14.98%	-12.85%
2012	136.65	1.91%	119.87	0.69%	163.81	2.60%	149.59	-1.10%	3.70%
2013	139.08	1.76%	120.36	0.41%	167.39	2.16%	152.80	2.12%	0.04%
2014	141.69	1.86%	121.41	0.87%	172.02	2.73%	161.88	5.77%	-3.04%
2015	143.15	1.03%	122.55	0.93%	175.43	1.96%	170.93	5.44%	-3.48%
2016	144.71	1.08%	121.98	-0.46%	176.52	0.62%	182.78	6.70%	-6.08%
2017	147.49	1.90%	122.90	0.76%	181.27	2.66%	183.50	0.39%	2.26%
Average Annual Growth Rate									
1997-2017		**1.85%**		**0.98%**		**2.83%**		**2.89%**	**-0.06%**

[1]All growth rates calculated logarithmically

[2]Gross Domestic Product Price Index calculated by the BEA.

[3]Multifactor productivity for the U.S. private business sector calculated by the BLS.

5.8. Kahn Method Research

A base X factor was also calculated for NGrid using a simpler “Kahn Method” exercise. This method was developed by noted regulatory economist Alfred Kahn, who was a professor at Cornell University. It has been used by the FERC to set the X factors in PBR plans for interstate oil pipelines. In an application to this proceeding, PEG would calculate trends in the cost of base rate inputs of a sample of power distributors using FERC Form 1 data and traditional cost accounting and then solve for the value of X which would have caused the trend in distributor cost to equal the trend in a generic RCI. The base X factor resulting from such a calculation reflects the input price and productivity differentials of utilities.

Calculating X Using the Kahn Method

PEG postulated a hypothetical generic revenue cap index like that in Relation [8a] with the following form:

$$\textit{growth Allowed Base Revenue}^{Utility} = \textit{growth GDPPI} - X + \textit{growth Customers}. \qquad [15]$$

We then calculated the trend in the cost of base rate inputs for each utility in the sample. In these calculations, capital cost was defined as the sum of depreciation and amortization expenses and return on rate base. We excluded costs that were unlikely to be addressed by trackers and riders in NGrid’s regulatory system. We calculated the value of X that would cause the trends in the costs of the sampled power distributors to equal the trends in the hypothetical RCIs with formulas like Relation [8] on average over the sample period. The full sample period considered by PEG was the twenty-one-year period, 1997-2017. PEG also considered results for shorter and more recent periods.

Results of this exercise can be seen in Table 5 below. For all sample periods considered, the average annual growth in cost was more rapid than the average annual growth in the GDP-PI. The average annual growth in the number of customers served was not large enough to close this gap. Thus, the X factor must be negative if the hypothetical RCIs are to track historical distributor costs on average. The Kahn X factor was **-0.41%** for the full 1997-2017 sample period. The analogous result for the Northeast sample was **-0.45%.**

Table 5

U.S. Power Distributor Kahn X Factor Calculations[1]

Year	GDP-PI[1]	Customers	Total Cost	Kahn X
	[A]	[B]	[C]	[D=A+B-C]
1997	1.72%	1.38%	2.66%	0.45%
1998	1.10%	1.56%	5.20%	-2.54%
1999	1.43%	1.29%	3.90%	-1.19%
2000	2.23%	1.44%	4.27%	-0.60%
2001	2.22%	1.97%	3.26%	0.93%
2002	1.52%	1.36%	0.17%	2.70%
2003	1.87%	0.83%	3.45%	-0.76%
2004	2.64%	1.20%	0.92%	2.92%
2005	3.06%	1.36%	3.09%	1.32%
2006	3.00%	0.47%	2.84%	0.63%
2007	2.66%	1.05%	5.41%	-1.70%
2008	1.89%	0.61%	3.50%	-1.00%
2009	0.78%	0.23%	2.03%	-1.02%
2010	1.16%	0.50%	3.74%	-2.08%
2011	2.06%	0.27%	3.12%	-0.80%
2012	1.91%	0.44%	2.45%	-0.11%
2013	1.76%	0.55%	1.89%	0.41%
2014	1.87%	0.58%	3.98%	-1.53%
2015	1.03%	0.76%	3.84%	-2.05%
2016	1.08%	0.92%	3.02%	-1.02%
2017	1.90%	0.79%	4.24%	-1.55%
Average Annual Growth Rates				
1997-2017	1.85%	0.93%	3.19%	**-0.41%**
2002-2017	1.89%	0.74%	2.98%	**-0.35%**
2007-2017	1.64%	0.61%	3.38%	**-1.13%**

Note: All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 80 power distributors.

[1]Gross Domestic Product Price Index calculated by the BEA.

6. X Factor Recommendations

6.1. Stretch Factor

The Company proposes a consumer dividend of 0.40% contingent on GDP-PI growth exceeding 2%. The 0.4% recommendation is based on a statistical benchmarking study by Dr. Lawrence R. Kaufmann, President of Kaufmann Consulting. Dr. Kaufmann has done work for PEG as a Senior Advisor, but he is not an employee of PEG, and he worked separately for NGrid in this proceeding. He reported in his testimony that NGrid's productivity level was about 27% below that of NSTAR Electric's over the 2014-16 sample period.

PEG was not asked by the AGO to consider Dr. Kaufmann's study. Accordingly, we take 0.4% as a given in what follows. We note, however, that it is controversial to make a stretch factor contingent on the inflation rate. Inflation has been sluggish in recent years and this may continue. The potential for productivity growth does not vary with inflation and this provision is rare in approved PBR plans. We accordingly do not believe that there should be a stretch factor contingency.

6.2. X Factor

PEG's review of the assembled evidence on industry productivity trends has the following highlights.

- Using our upgraded OHS results and LRCA's national data, the productivity differential of -0.52% and the inflation differential of 0.56% sum to an indicated base X factor of **0.04%.** The indicated base X factor using Northeast data was -0.64%.
- Using our GD method and national data, the productivity differential of -0.65% and the inflation differential of -0.06% sum to base X factor of **-0.71%.** The indicated base X factor using Northeast data is **-0.74%.**
- The indicated base X factor using the Kahn method and national data is **-0.41%.** The analogous result using Northeast data is **-0.45%.**
- Other plan provisions also merit consideration in the choice of an X factor. The stretch factor would be effective only when inflation exceeded 2%. A tracker treatment is proposed for certain grid modernization and electric vehicle costs. Costs of an upgraded vegetation management program would also be tracked.
- The RCI has no scale escalator, but this does not produce an implicit stretch factor equal to expected customer growth. Growth in other scale variables also matters. We have shown that the trend in peak demand matters, and this has been slowed by an aggressive DSM program.

Based on the assembled evidence, PEG recommends a **-0.60%** base X factor for NGrid. To this would be added the 0.40% stretch factor. The total X factor would then be -0.20%.

Appendix

Details of the PEG Productivity Research

This Appendix contains more technical details of PEG's productivity research. We first discuss our input quantity and productivity indexes, respectively. We then address our method for calculating input price inflation and capital cost.

Input Quantity Indexes

The growth rate of a summary input quantity index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and quantity subindexes.

Index Form

Each summary input quantity index used in the study was of chain-weighted Törnqvist form. This means that its annual growth rate was determined by the following general formula:

$$\ln\left(Inputs_t / Inputs_{t-1} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(X_{j,t} / X_{j,t-1} \right). \qquad [A1]$$

Here, in each year *t*,

$Inputs_t$ = Summary input quantity index

$X_{j,t}$ = Quantity subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in the applicable cost.

It is evident that growth rate of the index is a weighted average of the growth rates of the input quantity subindexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. Data on the average shares of each input in the applicable cost of each utility in the current and prior years served as weights.

Productivity Growth Rates and Trends

The annual growth rate in each productivity index is given by the formula:

$$\ln\left(\frac{Productivity_t}{Productivity_{t-1}}\right)$$
$$= \ln\left(\frac{Output\ Quantities_t}{Output\ Quantities_{t-1}}\right) - \ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}}\right). \qquad [A2]$$

The long-run trend in each productivity index was calculated as its average annual growth rate over the full sample period.

Input Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

Price Index Formulas

The summary input price indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula.

$$\ln\left(\frac{Input\ Prices_t}{Input\ Prices_{t-1}}\right) = \sum_j \frac{1}{2}\cdot\left(sc_{j,t} + sc_{j,t-1}\right)\cdot\ln\left(\frac{W_{j,t}}{W_{j,t-1}}\right). \qquad [A3]$$

Here, in each year *t*,

$Input\ Prices_t$ = Input price index

$W_{j,t}$ = Price subindex for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the subindex values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

A monetary approach was chosen to measure the capital cost of each utility. As discussed in Section 3.2 above, under this approach capital cost is the product of a capital quantity index and a capital (service) price index.

$$CK = WK \cdot XK.$$

GD was assumed. PEG took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity index in the benchmark year were based on the net value of plant as reported in the FERC Form 1. We estimated the benchmark year (inflation-adjusted) value of net plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year. The construction cost indexes (WKA_t) were the applicable regional Handy-Whitman Index of Cost Trends of Power Distribution Construction.[52]

The following formula was used to compute values of the capital quantity index in subsequent years:

$$XK_t = (1-d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad [A4]$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad [A5]$$

The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. This term was time-variant but smoothed to reduce capital cost volatility.

[52] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

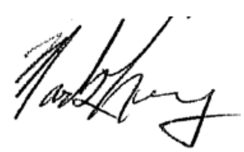
Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, Petition for a General Increase in Electric Rates	**D.P.U. 18-150**

AFFIDAVIT OF MARK NEWTON LOWRY

Mark Newton Lowry does hereby depose and say as follows:

I, Mark Newton Lowry, on behalf of the Massachusetts Attorney General's Office, certify that the testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the pains and penalties of perjury this 22nd day of March 2019.



Mark Newton Lowry