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September 20, 2013

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 1

On July 5, 2013, FBC filed the Application as referenced above. In accordance with Commission Order G-109-13 setting out the Preliminary Regulatory Timetable for the review of the Application, FBC respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

cc (e-mail only): Registered Parties

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A. PERFORMANCE BASED RATES PLAN

1.0 Reference: Exhibit B-1, p. 12-14

Productivity Focus

Fortis BC Inc. (FBC) states that, "During 2012 and 2013, employees were asked to consider embedded practices and rethink work while maintaining appropriate service levels. As a result, efficiencies were realized from streamlining processes, leveraging technology and optimizing opportunities for integration with FEI." (Exhibit B-1, p. 12) (Emphasis added)

1.1 Please clarify the statement that "efficiencies were realized." Is this referring to the Operating and Maintenance (O&M) sustainable efficiencies of $452 thousand, shown on Table C4-2?

Response:

The statement "efficiencies were realized" is in part referring to the O&M sustainable efficiencies of $452 thousand shown on Table C4-2.

A priority for the Company and its employees is to improve productivity and realize efficiencies in its operations. Discussed in Section A-3 of Exhibit B-1 and in the O&M department review in Section C4 are a number of examples of productivity achievements in 2012/2013 that FBC realized. These examples contributed to the $452 thousand of sustainable efficiencies as shown on Table C4-2, which represent the difference between the O&M approved in customers' rates in 2013 and that projected for the year.

However, FBC highlights that productivity achievements are not just about reducing costs. Productivity is more than just reducing costs. It is also about meeting increased demand for resources, including improving customer service and options, using the same amount of resources available.

FBC states that, "While the Company will continue its efforts to investigate productivity opportunities, future progress is expected to be somewhat slower given the highlighted challenges, and may require investments in IT systems or other initiatives." (Exhibit B-1, p. 14)

1.2 Please confirm that the efficiencies gained from the integration efforts will continue into the future?

Response:

Assuming business conditions and circumstances continue to support the current state of integration between the Gas and Electric businesses, efficiencies realized from past integration efforts are expected to continue into the future and have been embedded into the forecast Revenue Requirements.

1.3 Please explain why "future progress is expected to be somewhat slower?" Is this suggesting that the integration with FEI has been completed or nearly completed? Or is the above statement meant to convey that efficiencies within FBC will be slower? Why?

Response:

The statement "future progress is expected to be somewhat slower" does not mean that integration with FEI has been completed or nearly completed.

There may be further opportunities during the 2014 – 2018 period to achieve additional savings. However, as indicated on page 14 of Exhibit B-1, Section A3-3 Productivity Focus - 2013 and Onward, future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome some challenges. The challenges include concerns raised by unions representing gas and electric employees around shifting of unionized work from one entity to another, and the need to transition to common IT platforms before more harmonization of business processes can occur.

Additionally, differences in the nature of the electric and gas operations also pose challenges and limit the breadth of opportunities available. While both businesses provide an energy distribution service to customers, the differences in the form of energy (electricity versus natural gas) result in different operating practices and, in some cases, different skill sets, training and knowledge bases (i.e. construction, maintenance, safety, reliability, emergency response, government regulations, etc.) required to be able to provide service. Another consideration is the differences in the types of infrastructure and equipment used in both businesses (i.e. gas transmission and distribution pipelines, gate and compressor stations versus electricity transmission lines, poles and wires and substations). Also, the electric business owns generation assets to produce electricity, unlike the gas business which instead sources gas supply from the marketplace. These differences limit the opportunities and benefits of sharing operating practices.

In the last FBC revenue requirement proceeding[1], the Commission, in its Decision, stated:

"The level and speed of integration of common functions among the FortisBC group of companies was very much at issue in this proceeding. FortisBC states that the process is at an early stage as a number of key foundational elements (among these is the proposed amalgamation of the gas utilities) must be put in place. To date, the senior management teams of both organizations have been combined with the result that total executive costs in 2013 are projected to be only $13,000 higher than in 2007. Additionally, a Board of Directors has been shared by both organizations since in 2010, resulting in significant savings. FortisBC indicates that it is now about to start the process of looking for efficiencies through alignment of operational elements of the business…The Commission Panel, like BCMEU, would like to see the process of integration of common functions move forward more quickly. However, we accept that proceeding in this direction may not be a simple matter and must be done only after careful consideration. **Because of this, the Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014."** (2012-2013 RRA and ISP Decision)

1.4 In FBC's opinion, has the above directive for full exploration of integration been fully explored within this Application? If yes, provide the reference to where the results are fully explored in this application.

Response:

FortisBC remained committed after the 2012-2013 application to its efforts to realize on the opportunities that flow from integration, and believes that its present filing reflects that fact.

It views integration as a means to achieve further productivity/efficiency by focusing on managing the level of O&M funding required to operate the Company and has taken initiative to explore and implement integration opportunities. Those efforts are reflected in the Application.

[1] In the Matter of An Application by FortisBC Inc. for Approval of the 2012-2013 Revenue Requirement and Integrated System Plan, Decision dated August 15, 2012 (2012-2013 RRA and ISP Decision)

In the Application itself, FBC has appropriately explored the issue of integration within the context of the proposed PBR Plan by providing relevant discussions on integration opportunities when discussing O&M expenditures in the Application, consistent with the stated view above. For instance, FBC has outlined a number of productivity examples realized, some of which are associated with integration with the gas business. Please refer to section C4 Department O&M for examples (i.e. refer to page 145 of Exhibit B-1 Section C4.10.3 Operations and Maintenance Expense Review, Engineering Services and Project Management Review).

With regards to future integration and efficiency opportunities, as indicated in section A3.3 “Productivity Focus – 2013 and Onward,” FBC will continue to engage in efficiency review activities and to pursue productivity gains with the emphasis on managing costs. To the extent that such activities result in productivity savings in the future, they represent the Company’s efforts to achieving its productivity targets under the PBR plan. Further opportunities may emerge and will be evaluated depending on the circumstances and potential benefits to customers. Specifically, the Company has indicated (on page 13 of the Application) that

> “Future integration opportunities are expected to be more complex and dependent on the Company’s ability to overcome some challenges. These challenges include concerns raised by unions representing gas and electric employees around shifting of unionized work from one entity to another, and the need to transition to common IT platforms before more harmonization of business processes can occur. Differences in the nature of the electric and gas operations also pose challenges and limit the breadth of opportunities available. While the Company will continue its efforts to investigate productivity opportunities, future progress is expected to be somewhat slower given the highlighted challenges, and may require investments in IT systems or other initiatives to achieve significant and sustainable savings.”

For clarity with respect to the wording of the information request itself, we note that the passage quoted in the preamble expressed the Commission’s expectation (as stated in the wording of the quoted passage), not a “directive”. The Commission’s wording properly reflects the fact that integration between independent utilities could not be ordered, nor could an obligation to achieve savings through integration be imposed. The statement quoted above was presented within the context of FBC’s O&M budget, and was in the context of FortisBC’s commitment to take efforts to realize on the opportunities that flow from integration and its view, noted above, that integration is a means to achieve further productivity/efficiency by focusing on managing the level of O&M funding required to operate the Company.

2.0 Reference: Exhibit B-1, p. 13

Integration and Cost Allocation

"The O&M forecasts reflect a sharing of labour resources between the different electric and gas departments. Instead of using a Shared Services cost allocation model similar to that approved for allocating shared services costs among the FEU, a timesheet allocation approach is being used which allocates costs based on actual and/or specific estimates of time. Given the evolving nature of integration efforts between the electric and gas businesses, this timesheet allocation approach continues to be the appropriate approach to allocate the majority of shared costs between the two organizations. Consistent with the existing allocation of Board of Directors' costs, FBC is seeking approval to allocate Executive costs on the basis of the Massachusetts Formula…" (Exhibit B-1, p. 13)

2.1 Please discuss each of the different methods of cost allocation, including the pros and cons for each: Timesheet method, Shared Services cost allocation method, Massachusetts Formula. Please also explain which methods are appropriate for which types of costs and why.

Response:

All three of the cost allocation methods – Timesheet (employees providing services filling out timesheets), Shared Services (establish common cost pools and appropriate cost drivers), and the Massachusetts formula (a financial composite allocation calculated as an average of revenues, payroll and average NBV of tangible capital assets plus inventories) – may be more appropriate than the other methods under different circumstances.

Please refer to page 10 of the report titled "Corporate Services Cost Allocation Model" in Appendix F-2 of Exhibit B-1-1 for a list of cost driver assessment principles to consider when evaluating the appropriate cost driver / cost allocation method to use.

A key criterion in the choice of cost allocation approach is consideration for the cost causality principle. In this regard, typically the Timesheet approach has the highest correlation to the cost of the services. The challenge though is that as the number of financial transactions increases, the Timesheet approach becomes less cost effective and is not scalable. The administrative effort to support the Timesheet method including recording, processing and intercompany billing will increase as transactions and costs allocated increases. The Timesheet approach is more suited to ad-hoc situations and/or where common cost pools are not fully defined with cost drivers identified, as the Shared Services is still evolving. For example, in allocating costs where the scope of services is not firmly defined (i.e. current sharing labour arrangement between FBC and FEI which is still evolving), the Timesheet approach results in the most appropriate allocation of costs. As the integration efforts between Gas and Electric advance in the future, moving towards a Shared Services cost allocation approach or the Massachusetts formula may result in an appropriate allocation while increasing the cost effectiveness of the approach (i.e. reduced administrative effort).

In determining which of the three cost allocation methods to use, generally, as the scope of the services to be shared can be defined and cost drivers can be selected that results in appropriate cost allocations, then it makes sense to move away from the Timesheet approach to the cost driver approach such as the Shared Services or Massachusetts formula. As the Massachusetts formula approach is a defined industry approach using revenues, payroll and assets as cost drivers, it may not work as well in situations where the costs to be allocated have a weak correlation to the three cost drivers. As a result, a more customized, Shared Services approach, may then work better. Typically, application of the Massachusetts formula works well for allocation of corporate services type costs including Board of Director and Executive costs.

As discussed, each of the three cost allocation methods may work better under certain circumstances. In the end, the primary purpose of the cost allocations is to allocate costs in a reasonable and appropriate manner that the affected parties can agree to.

3.0 Reference: Exhibit B-1, p. 16

Customer Service Initiatives

FBC states: "Following the deployment of AMI [Advanced Metering Infrastructure], consumption information will be available on an hourly basis, allowing customers to analyse their consumption more effectively than ever before;" (Exhibit B-1, p. 16)

3.1 Is FBC suggesting that it may implement time of use rates in the future?

Response:

The cited statement is suggesting only that the more granular data that will be available to customers after the implementation of AMI will allow them to more effectively analyze their electricity consumption.

FortisBC made it clear in the recently approved AMI CPCN application that AMI enables time-varying rate structures, and that these rate structures could be made available as an optional rate, in future, based on the customer's preference. The CPCN also indicated that FortisBC was considering a possible application for such optional time-varying rates once AMI was fully implemented.

4.0 Reference: Exhibit B-1, p. 18

Balanced Scorecard

FBC states "FBC uses a Balanced Scorecard approach to deliver on a number of key success measures critical to the business. The performance assessment is integral for management in evaluating performance and in determining cost-effective service levels for customers going forward."

4.1 Please explain how the balanced scorecard is tied to executive and other employees' compensation as an incentive to achieve the financial, safety, customer and regulatory measures of the utility?

Response:

The balanced scorecard is tied to executive and other employees' compensation through the Company's Short Term Incentive (STI) Program. This STI program for eligible employees (i.e. management and exempt, executives, and certain unionized employees) is designed to recognize and reward employees whose performance contributes to the success of the Company's performance and results. The STI Program consists of a corporate scorecard component and a personal component. Eligible FBC employees receive annual incentive pay, based on the achievement of the corporate scorecard targets (i.e. financial, safety, customer, regulatory) and the employees' performance on their personal component.

4.2 For each of the four categories of measures please show the targets for 2014 and the actual results for the past five years.

Response:

Using the 2013 Scorecard's four categories with the associated six measures, following is a table showing the historical results and the targets for the last five years, from 2008 to 2012. Please note for the measures Regulatory Performance, Regulated Earnings and Recordable Vehicle Incidents, benchmarks for the purpose of the scorecard may not be available for some of the years as these measures were not previously included on the scorecard.

1

Category	Measure	2008		2009		2010		2011		2012		2014
		Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Target
Customer	Customer Satisfaction Index	8.6	8.5	8.6	8.5	8.8	8.5	8.7	8.5	8.4	8.5	n/a
	System average interruption duration index	2.42	2.57	2.28	2.61	2.84	2.40	1.86	2.40	1.95	2.33	n/a
Safety	All Injury Frequency Rate	2.87	1.84	1.41	2.13	1.72	2.00	1.48	2.00	1.72	1.54	n/a
	Recordable Vehicle incidents	27	n/a	22	n/a	27	n/a	32	n/a	22	31	n/a
Regulatory	Regulatory Performance	n/a	n/a	n/a	n/a	n/a	n/a	On Track	Subjective	Ahead	Subjective	n/a
Financial	Regulated Earnings $ millions	$ 31.0	n/a	$ 34.5	n/a	$ 38.3	n/a	$ 46.3	n/a	$ 48.5	$ 44.1	n/a

2

The scorecard for 2014 is not available at this time as the measures and targets have not been determined. For some measures, the determination of the appropriate benchmark for a given year was dependent on the prior year's results. These measures include AIFR, Recordable Vehicle Incidents and SAIDI where their target is based on a three year rolling average.

4.3 How does FBC measure achievements in the regulatory performance measure?

Response:

The Regulatory performance category highlights the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. Of importance is the Company's success in achieving reasonable regulatory decisions from the BCUC on the Company's regulatory applications while maintaining constructive relationships with stakeholders. This is measured subjectively.

4.4 FEI undertook a review of the performance measures of other Canadian utilities. Would any of the measures used by those utilities be applicable improvement to FBC's current balanced scorecard?

Response:

The study findings indicated that the FEU's scorecard is generally consistent with scorecards used by its peer group companies and incorporates comparable categories and performance. While the scope of the FEU's review efforts was focused on Canadian natural gas distribution utilities to reflect FEI's peer group companies, certain of the performance measures reviewed have applicability to an electric utility like FBC.

FortisBC, including FBC and the FEU, recently revised the corporate scorecard in 2012 with different measures selected to reflect the key areas of focus. The broad categories aligned the Gas and Electric businesses' scorecards, creating a common focus and consistency of measures reported between the two businesses.

FortisBC reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. In evaluating potential changes to the scorecard categories and measures, the Company seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding for employees and other stakeholders the understandability of a measure is an important consideration.

At this time, FBC believes the six scorecard measures used best represent the overall priorities for Company.

5.0 Reference: Exhibit B-1, p. 18

Balanced Scorecard

"FBC's current Scorecard is comprised of four categories of measures, which are standardized between the electric and gas businesses…The four categories of measures include Financial, Safety, Customer and Regulatory…" and "Net earnings for FBC is used as the financial performance measure taking into account earnings from revenues, operating and maintenance expenses, depreciation, amortization, property taxes, interest expense and income taxes. It incorporates the approved costs and revenues that are utilized in determining customers' rates each year." (Exhibit B-1, p. 18) (Emphasis added)

5.1 Please explain the 'financial' performance measure of the Balance Scorecard. What management actions is it meant to measure? Management's ability to forecast costs and meet net earnings? Or simply the ability to meet the forecast net earnings?

Response:

As indicated by Kaplan and Norton (1992),[2] "the financial measures indicate whether the Company's strategy, implementation and execution are contributing to bottom line improvements" and provide an answer to the question "how does the Company look to investors?". In this regard, the Net Earnings measure demonstrates the financial health of the Company and measures its ability to attract the necessary investments that are essential to safety and reliability of system and continued success in the rest of balanced scorecard's performance areas. This is in the best interests of customers, stakeholders and the shareholder.

The financial measure of Net Earnings is comprised of regulated earnings which take into account electricity revenues and other income less operational costs that have been approved by the BCUC. Regulated earnings also reflect the allowed return on equity as approved by the BCUC. Recognizing that the forecasted Net Earnings has been approved by the BCUC to provide a fair and reasonable return to the utility, the measure has been included on FBC's scorecard to highlight the importance of achieving a reasonable return.

To achieve the allowed Net Earnings which is approved by the BCUC, FBC's management takes action to ensure the approved controllable revenues and costs that contribute to Net Earnings are appropriately managed. Instead of having a number of different financial metrics including O&M on the scorecard, Net Earnings is a broader financial measure that encompasses the other financial metrics. Additionally, as the scorecard is an important

[2] Kaplan, R. S. and D.P. Norton (1992) The Balanced Scorecard: Measures that Drive Performance, *Harvard Business Review,* (January-February): 71-79.

communication tool to improving organizational alignment, clarity and understanding for employees and other stakeholders, the understandability of a measure is an important consideration. Net Earnings is a readily understood financial metric.

> "Employee safety is measured through the All Injury Frequency Rate (AIFR) which is the number of medical treatment injuries and lost time injuries per 200,000 work hours." (Exhibit B-1, p. 18)

5.2 During previous PBR periods, FBC has used additional metrics for employee safety, such as the Injury Severity Rate (ISR) and the Vehicle Rate (VIR). Please explain why these additional metrics are not used in the company's Balance Scorecard?

Response:

FBC clarifies that the additional metrics referred to such as Injury Severity Rate (ISR) and the Vehicle Rate (VIR) were included as performance standards used to assess the Company's performance as part of the previous PBR agreements. The metrics were not included as part of the Company's balanced scorecard.

FBC uses a Balanced Scorecard approach to deliver on a number of key success measures critical to the business whereas the performance standards are used more to ensure sufficient performance or service quality is provided under a PBR agreement. In some instances, the same metric is used as a service quality indicator and also as a scorecard measure.

When evaluating performance measures to include on its Scorecard such as employee safety metrics, FBC seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding of a measure, for employees and other stakeholders, is an important consideration. Please refer to the response to BCSEA IR 1.34.1 for how FBC uses its scorecard.

FBC currently uses AIFR and recordable vehicle incidents to measure employee safety. The current measures are similar in many respects to the ISR and VIR and align well with the same measures used in the gas business. FBC reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. At this time, FBC believes the six scorecard measures used best represent the overall priorities for Company.

FBC explains the two measures related to the Customer category of the Balanced Scorecard includes "customer satisfaction and system reliability. Customer satisfaction as measured through an index score is designed to reflect feedback from residential and business customers on the reliability of power, billing and call centre services, field services, energy conservation, community involvement and public safety. The System Average Interruption Duration Index measures the cumulative time that a customer's power is interrupted, on average, during the year, reflecting overall the overall reliability of FBC's power system." (Exhibit B-1, p. 18)

5.3 During previous PBR periods, FBC has used additional metrics for system reliability, such as the System Average Interruption Frequency Index and the Generator Forced Outage Rate. For customer satisfaction, FBC has used the additional metrics of Billing Accuracy, Meters Read as Scheduled, Contact Center (calls answered within 30 seconds), Emergency Response Time, Residential Connections and Extension (quotes and completions and completion time). To the extent that these previous metrics are different than the performance metrics that are included in the Balanced Scorecard, please provide explanations and why any would not be included in the Balanced Scorecard. Provide your response in table format for comparison.

Response:

Following is a table showing the history and evolution of SQIs used at FBC and in comparison to the current measures included in the Company's Balanced Scorecard. A copy of this table referenced as Table D6-2 without the Scorecard metrics column was included on page 3 of Exhibit B-1-1 Appendix D-6 Service Quality Indicators.

As discussed in the response to BCUC IR 1.5.2, when evaluating performance measures to include on its Scorecard, FBC seeks not only to select the appropriate success measures but also the optimal number of measures (i.e. how many). Additionally, as the scorecard is an important communication tool to improving organizational alignment, clarity and understanding of a measure, for employees and other stakeholders, is an important consideration. Please refer to the response to BCSEA IR 1.34.1 for how FBC uses its scorecard.

Given the above considerations, many of referenced metrics in the question used as service quality indicators in the past are not included on the scorecard. FBC also clarifies that service quality indicators were used primarily to assess the Company's performance as part of the previous PBR agreements which is different than most of the measures on corporate scorecard. FBC continues to monitor the service quality indicators and places different emphasis on personal scorecards depending upon where the focus should be.

FBC reviews the appropriateness of its scorecard measures periodically and makes adjustments as required. At this time, FBC believes the six scorecard measures used best represent the overall priorities for Company.

History and Evolution of SQIs at FBC (1996 - 2014)

	Service Quality Indicator	1996 PBR	2007 PBR	Proposed 2014 PBR	Scorecard
1	System Average Interruption Frequency Index	Included	Definition changed to Normalized	Included	-
2	System Average Interruption Duration Index	Included	Definition changed to Normalized	Included	Included
3	Customer Average Interruption Duration Index	Included	Discontinued	-	-
4	Index of Reliability	Included	Discontinued	-	-
5	Generator Forced Outages	Added (1999-2004)	Included	Discontinued	-
6	Generation Incapability Factor	Added (1999-2004)	Discontinued	-	-
7	Generator Operating Factor	Added (1999 only)	-	-	-
8	System Losses	Included (1996-1998)	-	-	-
9	Customer Satisfaction Index	Included	Included (Redesigned)	Included	Included
10	Billing Accuracy	-	Included	Replaced with Billing Index	-
11	First Contact Resolution	-	-	Included	-
12	Meters Read as Scheduled	-	Included	Included	-
13	Telephone Service Factor	-	Included	Included	-
14	Emergency Response Time	-	Included	Included	-
15	Residential Connections Completion Time	-	Included	Discontinued	-
16	Residential Extensions Quoting Time	-	Included	Discontinued	-

	Service Quality Indicator	1996 PBR	2007 PBR	Proposed 2014 PBR	Scorecard
17	Residential Extensions Completion Time	-	Included	Discontinued	-
18	Injury Frequency Rate	Included (Disabling Injury Frequency Rate)	Definition changed to All Injury Frequency Rate	Included	Included
19	Injury Severity Rate	Included	Included	Discontinued	-
20	Vehicle Incident Rate	Included	Included	Discontinued	-
*	Recordable vehicle incidents	-	-	-	Included
*	Regulatory Performance	-	-	-	Included
*	Financial	-	-	-	Included

5.4 Please confirm that the four measures in the Balanced Scorecard are all equally weighed.

Response:

For 2013, for the four scorecard categories, approximately equal weightings have been assigned with Regulatory at 25%, Customer (CSI and SAIDI) at 25%, Safety (AIFR and recordable vehicle accidents) at 20% and Finance at 30%. A slightly higher weighting is assigned to the Finance category measured by Net Earnings, recognizing the importance of achieving a reasonable return and ensuring a financially healthy company.

B. MULTI-YEAR PBR MECHANISM

6.0 Reference: Exhibit B-1, p. 24

PBR Plan

"FBC's PBR experts, [Black & Veatch] B&V, has studied the available PBR methodologies and provided their its [sic] recommendations on FBC's proposed PBR Plan model in Appendix D1 *Comparison of Recent Performance Based Regulation for Distribution Utilities in Canada…"*

6.1 Please confirm that FBC intends to apply the proposed PBR mechanism to the whole of its services (generation, transmission, and distribution), as opposed to only 1 business segment (i.e. distribution services only).

Response:

Confirmed. FBC intends to apply the proposed PBR mechanism to the whole of its vertically integrated components generation, transmission, and distribution.

6.2 If yes, please explain how the B&V Report on "distribution utilities" is appropriate for FBC's vertically integrated business?

Response:

B&V provides the following response.

First, the B&V report is not just for distribution utilities. The analysis includes transmission where the utilities in the sample still own and operate transmission facilities. Second, the FBC electric business is unique with respect to its generation assets (hydroelectric facilities) as compared to most of the utilities in the sample. Because of this unique aspect, there is little basis for including a production component in the TFP analysis (representing only about 16% of the net assets of the utility). Any capacity expansion has been or will be subject to the CPCN provision of the plan, meaning that it will be outside of the I – X mechanism where TFP is relevant. For other expenses and capital the development of a principally transmission and distribution TFP matches the sample closely. Finally, controllable costs for the generation facilities are small compared to the non-fuel and purchased power costs and there is little reason to include generation in the calculation of TFP.

7.0 Reference: Exhibit B-1, Table B5-1, pp. 36-37

Jurisdictional Comparison

7.1 Please provide the references used for each of the five PBR plans included in Table B5-1. If these sources are available on the internet, please provide the web address for each reference.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.1.1. This response is identical to the FEI response to that IR.

Please refer to the table below detailing the titles and links of the references used for each of the five PBR plans included in Table B5-1 of the Application:

Utility/Jurisdiction	Title	Link
Alberta Electricity and Natural Gas	**Decision 2012-237** - Rate Regulation Initiative, Distribution Performance-Based Regulation	http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-237.pdf
Union Gas Limited	**Decision EB-2007-0606** - Application for an Order or Orders approving or fixing a multiyear incentive rate mechanism to determine rates for the regulated distribution, transmission and storage of natural gas, effective January 1, 2008	http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0606/dec_union_enbridge_20080117.pdf
Enbridge Gas	**Decision EB-2007-0615** - Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2008	http://www.ontarioenergyboard.ca/documents/cases/EB-2007-0615/dec_union_enbridge_20080211.pdf
Enbridge Gas and Union Gas	PEG's report -Assessment of Union Gas Ltd. And Enbridge Gas Distribution Inc. Incentive Regulation Plans, September 2011	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0052/PEG_Final%20Report_20110930.pdf
OEB's Power Distributors	**Report of the Board** - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 2012	http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf
OEB's Power Distributors	**Report of the Board** - on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 2008	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_Generation_20080715.pdf
OEB's Power distributors	**EB-2007-0673** - Supplemental Report of the Board, September 2008	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf
OEB's Power distributors	**EB-2007-0673** - Addendum to the Supplemental Report of the Board, January 2009	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Addendum_Suppl_Report_20090128.pdf
Gaz Metro (Official version)	**Decision D-2007-47**, "Motifs de la décision D-2007-47 portant sur le renouvellement du mécanisme incitatif à l'amélioration de la performance", May 2007	http://www.regie-energie.qc.ca/audiences/decisions/D-2007-47Motifs.pdf
Gaz Metro (English version)	Performance incentive mechanism, Agreed in NSP R-3599-2006 (Translation – Not approved by Participants)	http://www.corporatif.gazmetro.com/data/media/gazmetro%20performance%20incentive%20mechanism.pdf?culture=en-ca

7.2 For each of the five plans in the table, provide the specific X-Factor values that were approved for the plan.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.1.2. This response is identical to the FEI response to that IR.

The approved X-Factor values for each of the five PBR plans are presented in Table 1 below:

Table 1: X-Factor values and determination methodologies for each of the five PBR plans

Utility/Jurisdiction	PBR Period	Methodology	X-Factor
Alberta	2013-2017	TFP (0.96%) + Stretch factor (0.2%)	0.96% + 0.2% = **1.16 %**
Union Gas	2008-2012	Negotiated Settlement (Not based on any specific study)	**1.82%**
Enbridge Gas	2008-2012	Varied based on different percentage of inflation index (GDP IPI FDD)	Varied **between 0.36% and 1.22%** (see Table 2 below)
Ontario's power distributors (3rd Generation IR)	2009-2013	TFP (0.72%) + 3 cohorts of Stretch factor (0.2%, 0.4% or 0.6%)	0.72% + (0.2%; 0.4%; 0.6%) = **(0.92%; 1.12%; 1.32%)**
Ontario's power distributors (4th Generation IR)*	2014-2018	Judgment-based value (0%) + 5 cohorts of Stretch factor (0 %, 0.15%, 0.30%, 0.45%, 0.6%)	0.0% + (0 %, 0.15%, 0.30%, 0.45%, 0.6%) = **(0.0%; 0.15%; 0.30%, 0.45%, 0.6%)**
Gaz Metro	2007-2012	Negotiated. (Reflective of the historical rate increases and inflation).	**0.3%**

* The TFP value calculated and proposed by the OEB's consultant (OEB has used the services of the same consultant in 3rd and 4th Generation IRs) however the X-Factor value is not yet approved by the OEB. The TFP value is estimated at – 0.33% but based on expert judgment PEG is proposing a zero percent TFP value to be added to 5 different stretch factors.

Enbridge Gas' X- calculation of its implicit X-Factor is further detailed in Table 2 below:

Table 2: Enbridge Gas' implicit X-Factor calculation based on actual inflation rates

	2008	2009	2010	2011	2012
Coefficient (C)	0.6	0.55	0.55	0.5	0.45
Inflation (I)	2.04%	1.54%	2.73%	0.72%	1.72%
Implicit X = I * (1-C)	**0.81%**	**0.69%**	**1.22%**	**0.36%**	**0.94%**

8.0 Reference: Exhibit B-1, p. 38

Service Quality Indicators (SQI)

FBC states "In Alberta and Ontario the SQIs are monitored during the PBR plan however there is no direct reward or penalty mechanism attached to SQIs. Gaz Metro is the only utility among those reviewed that has had SQIs with financial penalties or rewards."

8.1 Please discuss how the Gaz Metro SQIs produce financial penalties or rewards.

Response:

This question is similar to FEI's 2014-2018 PBR Application, COPE IR 1.7.5. This response is identical to the FEI response to that IR.

As indicated in Table B5-1 of the Application, the SQIs in Gaz Metro's 2007-2012 plan were linked to financial incentives. According to Gaz Metro's settlement, Gaz Metro's claim of the performance incentive is dependent on its ability to meet the selected Service Quality Metrics agreed to in the Settlement. A higher achievement equaled a higher claim of the performance incentive or over earnings as described in the table below:

Overall attainment percentage	Percentage of performance incentive awarded
0% to 84%	0%
85% +	corresponding percentage

The overall attainment percentage was calculated based on the weighted average of results achieved for individual service quality indicators. The attainment percentage for individual SQIs was calculated based on the following formula[3]:

$$B = (R - 50\,\%) * \frac{85\,\%}{(C - 50\,\%)}$$

Where

B = Resulting percentage for indicator (maximum 100%)

R = Percentage achieved for indicator

C = Percentage target result for indicator, i.e. 85%, for all indicators except one which was 75%

[3] Two SQIs attainment percentages were determined by non-formula mechanisms.

In addition, to ensure Gaz Metro did not neglect service quality when in a shortfall situation, it agreed to reimburse customers between $100 thousand (for seven SQIs) and $200 thousand (for two SQIs) for each of the SQIs for which a minimum 85% score is not attained.

9.0 Reference: Exhibit B-1, p. 39

Principle 3: Unique Circumstances

9.1 Please explain FBC's unique circumstances that are relevant to the PBR design.

Response:

The Company interprets this question to ask about FBC's unique circumstances in BC relative to those circumstances that exist in other Canadian jurisdictions such as Alberta and Ontario.

FBC's long standing experience with PBR back to 1996 differentiates it from Alberta, for instance. PBR has been a success for both the Company and customers, producing real savings and efficiencies since that time. Based upon this previous experience, FBC has proposed a more comprehensive PBR (including formula driven capital). Further the Company does not have significant volatility in O&M and capital which is an additional unique factor associated with the form of PBR that FBC has proposed.

In the case of Alberta, there is relatively little experience with PBR. The AUC just concluded its generic PBR proceeding in 2012, and certain aspects of the resulting plans have yet to be resolved. Further the generic plan in Alberta is used by the numerous gas and electric utilities in Alberta, whereas FBC's Plan is custom designed to suit its circumstances within BC.

In Ontario, the 4th Generation Incentive Regulation proceeding, applies to the over 70 electric utilities.

Please also refer to the response to BCUC IR 1.15.1 for a discussion of the different circumstances leading to the determination of the X-Factor in different jurisdictions.

10.0 Reference: Exhibit B-1, p. 39

PBR Principles

10.1 This section refers to "principles and objectives articulated below" (line 3, p. 39) but only lists five principles. What are the objectives?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.2.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC did not intend to distinguish between principles and objectives. They are essentially one and the same. FBC's objective was to achieve the principles to the extent reasonably possible.

FBC states "There are many ways to articulate principles and objectives, and B&V is aware that various jurisdictions do articulate them differently" (lines 4-6, p. 39).

10.2 Provide the other principles and objectives that B&V and FBC considered (including the references) when it developed the five principles in this section.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.2.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Black & Veatch (B&V) states that this is a reference to the fact that both economic literature and studies filed before regulatory bodies express principles and objectives (both terms are used to describe what we have labeled as principles) in slightly different terms. Please refer to, for example, the following industry publications in addition to the AUC Order filed in the case presented as Appendix D-9:3 of the Application:

- "WHAT THE LITTLECHILD REPORT ACTUALLY SAID", Jon Stern, London Business School & NERA, Regulation Initiative Working Paper No. 55, p.6 referencing the Littlechild criteria.
- System Operator incentive schemes from 2013: principles and policy, OFGEM, 31 January 2012, p.6.

- "Performance Based Regulation of Utilities: Theoretical Developments in the Last Two Decades", March 2010, C. R. (Sid) Carlson, The Van Horne Institute, pp. iv-vii.
- "Performance-Based Regulation of Utilities", Mark Newton Lowry and Lawrence Kaufman, The Energy Law Journal, 2002, pp.400- 401.

The set of principles filed by FBC in this proceeding reflects input from these sources as well as the general knowledge and experience of FBC and B&V related to incentive regulation and PBR specifically.

11.0 Reference: Exhibit B-1, pp. 41-42

Term

FBC proposes a five-year term for its PBR plan.

11.1 Discuss the merits of having an option to extend this plan, with the agreement of FBC, interveners, and the Commission, for an additional period. If such an optional extension were incorporated into the plan, what would be the length of such an extension? Two years, five years, or some other term?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.3.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

FBC is willing to consider an optional extension to the plan. The main benefit of a PBR plan extension would be to enable the utility to continue to pursue efficiency gains in the targeted areas (i.e. O&M and capital expenditures) over a longer period. A plan extension option should be viewed simply as another item in the overall balance of opportunities and benefits presented by a PBR plan. Just as plan elements such as the initial term, the X-Factor, exogenous factors, off-ramps, earnings sharing mechanisms and others need to be considered as an entire package, a plan extension option would be another item to consider in evaluating the overall balance of a PBR plan.

The length of the extension period cannot be specified without giving consideration to any other terms and conditions associated with the extension, or to related provisions of the PBR plan.

FBC believes that it is possible to develop an extension provision that would fit into the proposed PBR plan and would permit continued benefits to be achieved for customers and the utility. However it may be appropriate to consider an extension provision as part of the Mid-Term Review after actual experience with the PBR has occurred.

12.0 Reference: Exhibit B-1, pp. 42-44

Inflation Factor (I – Factor) Proposal

FBC states on page 44 that it "will update both the BC-AWE and BC-CPI rates (using the same sources referenced above) to determine the value of the I-Factor for the 2015 through 2018 years" (lines 12-14, p. 44).

12.1 What exactly does it mean to update the inflation rates? Is this a true-up of the forecast to the actual inflation rates? Provide an explanation of how this updating would work and a numerical example.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.4.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Each of the sources listed in Table B6-2 of the Application (Toronto Dominion Bank, Royal Bank, Bank of Montreal, Canadian Imperial Bank of Commerce, Conference Board of Canada and the BC Ministry of Finance) provide updates of forecast BC CPI rates. Additionally, the Conference Board of Canada provides updated forecasts of BC Average Weekly Earnings.

Each year at the Annual Review, FBC will present updated forecasts to determine the composite inflation rate that will be utilized in the I-X mechanism for the upcoming year. FBC will not adjust previous inflation rates to the actual inflation rates. Except for the use of a composite inflation factor, the annual reforecasting of inflation for the purpose of determining the I-Factor is the same approach as was used in FBC's 2004 PBR Plan.

12.2 If this updating is not a true-up to the actual inflation rate, then discuss the reasons for not truing up the inflation forecast to the actual inflation rate. What are the consequences of not including a true-up in the PBR plan? Provide a numerical example.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.4.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

The updating is to reflect more recent known data in the forecasts, as opposed to a true-up in the sense of adjusting previous inflation rates to the actual inflation rates.

FBC's customer rates are set prospectively each year at the Annual Review. The Annual Review occurs in the fall of each year, and actual inflation rates are not known at that time. However, in order to apply an I-X mechanism that is indicative of the inflation rate for the coming year, each year at the Annual Review, FBC will provide updated BC-CPI and AWE forecasts for the coming year.

The impact of not including an adjustment for the actual I-Factor in the PBR plan will depend on whether the composite actual inflation rate is above or below the forecast level. If the forecast I-Factor is lower than the actual, then customers will pay a slightly lower unit rate. Conversely, if the forecast inflation rate is higher than the actual rate, customers will pay a slightly higher unit rate. The forecasts are sourced from independent third parties, and FBC does not believe there will be any material impact of not adjusting the forecast composite I-Factor to the actual level. The revenue requirement impact of any small differences, one way or the other, between the forecast and actual I-Factor results will be caught up in the 50/50 earnings sharing mechanism, further diminishing any effect.

The I-X formula is estimated to affect approximately 18 percent of the delivery revenues. Therefore a 0.25% variance between the forecast and actual I-Factor calculation would (after earnings sharing) have a net effect on the delivery rates of 0.18 x 0.25% x 50% = 0.023%. As stated previously this small difference could be in either direction and there is no reason to believe it will be sustained into subsequent years.

12.3 What is the difference in terms of the effect on the company's revenues if the inflation factor is trued up or not trued up?

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.4.3. This response is similar to the FEI response to that IR.

As described in the response to BCUC IR 1.12.2, the updating is to reflect more recent known data in the forecasts, as opposed to a true-up in the sense of adjusting previous inflation rates to the actual inflation rates.

An updated forecast of both BC-CPI and AWE will be presented each year at the Annual Review to ensure that the I-Factor utilized in the I-X mechanism is representative of market conditions and will provide a forecast that is as current and accurate as possible. FBC has every reason to believe that the independent third party forecasts utilized in the I-Factor calculation will be reasonable. While there may be small variations from year to year in revenues, either positive or negative, arising from differences in the forecast and actual I-Factor results, there is no basis to say that not trueing up to actual will cause any net effect on FBC's revenues over the term of the PBR.

13.0 Reference: Exhibit B-1, pp. 42-44

Inflation Factor (I–Factor) Proposal

FBC states that it "believes it is more appropriate to use a composite labour and non-labour inflation index in determining the I-Factor since this is more reflective of Company costs, which consist of both labour and non-labour components, than an economy-wide inflation measure such as CPI." (p. 42)

In the proposed equation for the I-Factor, FBC makes some allowance for labour escalation by using a composite measure of inflation.

13.1 Does FBC agree that the BC Consumer Price Index (CPI) is only for the material component of costs? How does FBC plan to account for market conditions and commodity fluctuations that was experienced in the Kettle Valley project?

Response:

FBC agrees that CPI does account for the materials component of costs, hence the Company has proposed a weighted composite inflationary factor comprised of both BC CPI as well as BC Average Weekly Earnings to account for both materials inflation and labour inflation.

With respect to market conditions and commodity fluctuations that exceed the applicable annual inflationary impact applicable to the PBR formula, FBC will be responsible for managing the impact of these fluctuations for the O&M and capital expenditures subject to the PBR formula. This may require certain projects to be rescheduled and/or re-prioritized as required. For capital projects subject to a CPCN application, the Company will endeavour to identify the risk of market and/or commodity fluctuations at the time of the submission of the CPCN, and include appropriate inflationary adjustments and/or contingencies to address the possibility of such fluctuations. This issue was discussed in more detail in Section C5.3.4 "Inflation Assumptions" of Exhibit B-1.

14.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

On page 44, FBC states that the X-Factor "represents the amount by which a company is expected to outperform the industry and economy-wide productivity gains" (lines 18-19).

14.1 Please explain FBC's understanding of the X-Factor.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.5.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC and cross references. It responds to BCUC IR 1.14.2 and 1.14.3 as well.

A review of economic literature indicates that the definition of X-Factor varies from jurisdiction to jurisdiction and typically depends on the methodology used for determination of X-Factor value. For instance, Swinand (2003)[4] explains that depending on the jurisdiction, the X-Factor might be defined as "the measure of total factor productivity growth in its purest sense, or it could merely be considered a measure of how prices should change; or X could be considered a relative measure of productivity; or even a relative measure of productivity relative to price changes." In other research the Federal Communication Commission defines the X-Factor as "the amount by which a company is expected to outperform the economy-wide productivity gains."[5] The FCC's articulation mirrors what FBC has said on page 48 of the Application.

B&V explains that the X-Factor could be defined as "a measure of productivity growth in the industry in question" if a pure- TFP approach (where the X-Factor equals to the measured TFP) is used to determine the X-Factor without any additional stretch factor applied to it. However the majority of approved X-Factors in Canada (such as the ones in Alberta or Ontario) also include an additional percentage applied to the X-Factor (implicitly or explicitly). In this context and in choosing to propose an X-Factor that includes greater productivity than the TFP, FBC is undertaking to perform better than the industry, based on the adoption of the PBR model in its proposed form.

B&V's and FBC's view is that a utility's PBR Plan using I-X does not by itself provide a reasonable opportunity to earn the allowed rate of return even if its productivity growth exceeds the productivity calculated on the historical industry trend because the cost side of the operation is only one part of the determination of earned return. The Plan does not address issues with volumetric recovery of fixed costs and the resulting revenue impacts. To provide a reasonable

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4 Swinand, G. "An empirical examination of the theory and practice of how to set X". London Economics, 2003.

5 http://hraunfoss.fcc.gov/edocs_public/attachmatch/FCC-12-153A1.pdf (page 3, section 3).

opportunity to earn the allowed rate of return, a PBR Plan must be comprehensive and address exogenous cost impacts (collectively known as the Z-Factor concept) as well as issues related to growth, costs, revenue recovery and so forth. This is why FBC's proposed PBR Plan includes a number of other elements beyond the simple I-X formulaic configuration. Without the inclusion of all design elements of the Plan, there is no reasonable opportunity for an individual utility to earn its allowed rate of return. In particular, this is also why a "one size fits all plan" is not reasonable. Consistent with that conclusion, we see the OEB moving away from a single PBR plan design for all electric distribution utilities under its jurisdiction and adopting different PBR plans for Enbridge and Union Gas Limited.

14.2 Does FBC agree that the X-Factor is a measure of productivity growth in the industry in question? If this is FEI's understanding of the X-Factor, please reconcile this with the statement quoted above.

Response:

Please refer to the response to BCUC IR 1.14.1.

14.3 Under a PBR plan characterized by I-X, does FBC agree that the company has a reasonable opportunity to earn its allowed rate of return if its own productivity growth equaled the productivity growth of the industry as measured by X? Please discuss.

Response:

Please refer to the response to BCUC IR 1.14.1.

15.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

15.1 Compare the 0.5 X-Factor FBC is recommending with the most recent approved X-Factors for the companies identified in Table B5-1, Jurisdictional Comparison. What are the differences in the studies used to support each of the X-Factors?

<u>Response:</u>

This answer responds to BCUC IR 1.15.1 and 1.15.2.

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.6.1. This response is similar to the FEI response to that IR, however some changes were necessary in order to respond appropriately for FBC.

Please refer to the response to BCUC IR 1.7.2 for the comparison of the approved X-Factor values and the methodologies used for their determination in each of the mentioned PBR plans. FBC and B&V do not agree with the stated premise of BCUC IR 1.15.2 that "other X-Factors [in other jurisdictions] are higher than the 0.5 recommended by FBC", as it is an over-generalization. FBC's proposed 0.5 X-Factor is:

- higher than the average X-Factor for the electric utilities in Ontario as recommended by PEG in the September report update (including being less than the X-Factor for all but the 17 least efficient distributors); and
- lower than the X-Factors applied to Alberta's electric utilities, which is based on an earlier time period.

The shortcomings of the Alberta study have been discussed at length in FBC's Application. Briefly, the study was for the distribution accounts for electric utilities with no costs or outputs for transmission or general plant. Regardless of this issue, B&V and FBC consider that the difference between X-Factor values can be assessed and reconciled from four perspectives:

The year in which the X-Factor is determined: As discussed in the AUC's Decision 2012-237 (Page 63, Paragraph 300), since the year 2000 the productivity growth "has been declining at the approximate rate of -1.4 %". In addition, the AUC acknowledges that the addition of 2008 and 2009 data in their TFP study (despite the very long measurement TFP study period) decreases the X-Factor by almost 0.2%[6]. This downward trend was also restated by B&V in its review of the historic trend of approved TFP values in a sample of North American jurisdictions

6 Considering the continued decrease in use per customer and continued increase in infrastructure replacement costs, it is logical to believe that an update of NERA's TFP study with 2010 and 2011 data (Assuming everything else is unchanged) will lead to similar decrease in measured TFP value.

as presented in Figure B6-1 of the Application. Therefore regardless of the methodology used to determine the X-Factor, it can be concluded that the approved X-Factor values would have been lower if they were determined today. In Ontario, OEB's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study conducted by the OEB's consultant was estimated at 0.72 per cent, while the most recent study (based on 2002-2012 evidence) prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative TFP growth of - 0.33 per cent[7] and proposes an X-Factor of zero percent. It is worth mentioning that an earlier version of this study based on 2002-2011 data computed an industry TFP growth of 0.1 per cent[8].

Differences among utilities' business profiles: The differences among utilities may have a significant influence on productivity improvement opportunities and therefore the reasonableness of the X-Factor value. This emphasizes the point made in response to BCUC IR 1.14.1 above that one size does not fit all for PBR plans. The best example of this is the PEG study defines five different X-Factors appropriate for the Ontario electric distribution utilities. The inclusion of transmission facilities in the FBC TFP study as well as the inclusion of general plant appropriately reflects all of the inputs required to produce outputs in the current period. The Alberta study was insufficiently comprehensive to rely on as a measure for FBC.

Level of productivity gains prior to the start of the current PBR plan: 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 FBC that has years of recent experience with PBR and fewer available productivity improvement opportunities.

Other elements of PBR plan: Finally, comparing the X-Factor values of other PBR plans without considering the other elements of the plan (the total PBR package) may lead to erroneous conclusions. The cumulative effect of PBR elements such as SQIs, ESM, off-ramps, term, etc. may all impact the reasonableness of a particular X-Factor approved for a specific utility or jurisdiction.

When all of these factors are considered, FBC's X factor is reasonable, and in B&V's view more challenging than what its analysis would suggest.

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7 http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379%202012_PEG_Report_on_Empirical_Work.pdf

8 http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf

15.2 What are FBC's justifications for departing from the X-Factors approved in other jurisdictions, particularly when these other X-Factors are higher than the 0.5 recommended by FBC?

Response:

Please refer to the response to BCUC IR 1.15.1.

16.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

On page 44, FBC states that "The proposed .5 percent expected productivity gain exceeds the measured industry productivity levels and represents a real challenge to the Company to seek additional efficiency and continue with its productivity improvement culture" (lines 31-33, p. 44).

16.1 Please provide the justification, being as specific as possible and providing references, for the statement that the 0.5 X-Factor exceeds the measured industry productivity levels (productivity growth rate). Reconcile this statement with the X-Factors approved for the other companies listed in Table B5-1, Jurisdictional Comparison, and the studies used to support these X-Factors.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.7.1. This response is similar to the FEI response to that IR, however some differences were necessary in order to respond appropriately for FBC.

Based on the latest available studies of gas and electric productivity, the X-Factor values have declined below those noted in Table B5-1 of the Application (please refer to the response to BCUC IR 1.15.1). Since the values reported in Table B5-1 reflect older studies, and as noted often are not based on industry specific analyses, there is every reason to believe that FBC's proposed X-Factor is above the industry productivity factors. BC retained B&V to complete a TFP study based on electric utilities using a theoretically sound TFP methodology, and it shows negative TFP values, as explained in detail in B&V's Productivity Report.

In addition the recent TFP studies in Canada substantiate this claim that the current productivity growth rates are negative. For example the latest TFP study conducted by PEG on behalf of the OEB for its latest customized IR Plan (updated for 2012 data) demonstrates a negative value, despite having some theoretical issues that B&V's study has addressed in its report.[9] As discussed in Appendix D-1 the results of the AUC study for electric utilities produces unreliable results and contains a number of flaws.

[9] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379%202012_PEG_Report_on_Empirical_Work.pdf

17.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

On page 45, in the sub-section titled "the measurement period" for Total Factor Productivity (TFP) studies, FBC makes the statement that "In general it makes sense to use the most recent data, unless the recent past exhibits anomalous events that are not expected to continue during the PBR term" (lines 31-33).

17.1 Provide references to the economics literature that supports this statement: What are the reasons to use a short-term TFP calculation based on the recent past as opposed to calculating a longer-term TFP growth rate using all of the historical data available?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.8.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V advises that this is a direct quotation from a report prepared by the Brattle Group for the Australian Energy Markets Commission at page 4[10]. The economic literature provides that the X-Factor may be either historic or forecast[11]. There is no discussion related to using the most current data in theoretical studies as that is not an issue of the analysis because all studies use the most current data available. The main issue is how far back the data analysis must be extended. As discussed in Appendix D-1 of the Application, the use of volumetric output data would require a longer time period to average out weather impacts on TFP estimation. Further, it is assumed in most studies that volume is a measure of output (an assumption appropriate for the manufacturing process, and thus typically used in academic literature), thus, increasing the required study period. However, the longer study periods would overstate the impact of technological change on the expected TFP value during the regulatory control period when the technological change has been fully implemented as is the case for activities such as live main insertion and directional boring, for example. Given that the electric utility industry is a mature industry with common practices and methods, it is reasonable to assume that TFP gains based on the new technologies introduced in the past have been fully implemented in the current period. To the extent a new technology becomes available during the regulatory control period, the adoption of that technology as soon as feasible is part of the incentive aspect under PBR. Both FBC and its stakeholders are protected by the balanced ESM in the overall PBR plan.

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10 "Use of TFP analysis in network regulation case studies of regulatory practice", Toby Brown & Boaz Moselle, 2008.

11 See "Regulation: Price Cap and Revenue Cap" , Mark A. Jamison, Public Utility Research Center, University of Florida

From a theoretical perspective, the estimates of TFP relate to the production function which has a short-run and a long-run dimension. Any number of basic economic texts explain the elements of the short-run and long-run. In particular, the concept of the short-run is a period when all factors of production are fixed. In the long-run at least some factors of production can vary as would be the case for a five-year PBR Plan. These issues are discussed in the gas productivity report prepared by B&V related to the term of the included TFP study. The use of the near-term reflects the long-run considerations of some fixed factors of production. In addition, the use of the shorter time period is appropriate because it reflects the full implementation of technology changes that are reflected as productivity gains in historic periods. See for example the discussion of the AUC report in Appendix D-1 of the Application. There is no basis for using 20 or 30 years of data when output is properly specified as in the TFP study.

17.2 How can the Commission be assured that the shorter-term TFP growth calculation will be more indicative of the next five years of TFP growth for the industry rather than the longer-term TFP growth figure? For example, if the economy were in a recession or a slow-growth period for the recent short term period used to calculate TFP, would the TFP resulting from that study be a good indicator of the TFP in the next five years if the economy recovered to a period of more rapid, normal growth?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.8.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

B&V notes that, in the same way that utility regulators use the most recent data for operations to estimate test year costs and revenues, the Commission implicitly understands that current trends are more representative than factors from 20 or 30 years ago. A simple example will illustrate this point. Twenty years ago the Financial Accounting Standards Board (FASB) adopted FASB 106 that changed the accounting for post-retirement benefits from pay as you go to accrual accounting. If one looked at 30 years of data, there would be a significant change in the cost of labor as the result of this change (assuming the cost was included in the data for input costs). All else equal, this change would reduce TFP levels in current periods. However, by averaging in lower labor costs and higher TFP amounts in the early years, current TFP estimates would be higher than the post FASB 106 period. This is a simple example that by no means represents a comprehensive list of all of the reasons that current data is preferred over data from long historic periods. Other examples include the impact of changing regulations on operating costs such as the changes to the regulations governing meter sampling or measurement accuracy, the safety emphasis that has led to accelerated replacement and betterment programs for electric infrastructure, and so forth.

The issue of the impact on TFP of a slow growth period historically and a more rapid growth period subsequently is more an issue with volumetric measures of output. Using capacity as a measure of output, or customers and capacity, would not change the underlying productivity trend in any significant way with the exception of an electric utility expanding to serve a previously unserved area that requires extensive new investment to interconnect the area to the existing delivery infrastructure. Since these are events that typically require a CPCN, they would be outside FBC's PBR Plan.

18.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

On page 45, FBC says that "evidence from other North American jurisdictions where PBR design has considered TFP analysis, demonstrates that the length of the study period for calculation of TFP varies between 5 and 20 years" (lines 34-35).

18.1 Provide the evidence, with references to the studies and web locations when available, that FBC relied on to support the statement that the length of the study period for calculating TFP varies between 5 and 20 years. If these studies are not available online, provide copies of the studies in searchable PDF format.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.9.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

The table below includes some of the evidence that confirms FBC's statement. In addition, the suggested time frames for TFP studies by the majority of experts in the AUC's Decision 2012-237 (with the exception of Dr. Makholm from NERA) lie within this range.

Prepared for	Title of study	Sample period	Link
Quebec - Régie de l'Energie	Research for Gas Metro's Performance Incentive Mechanism	10 years (2000-2009)	http://www.regie-energie.qc.ca/audiences/3693-09_2/Demande_3693-09_2/B-25_GazMetro-2Doc1_3693-2_2sept11.pdf
OEB – Natural gas LDCs	Price Cap Index Design for Ontario's Natural Gas Utilities	11 years (1994-2004)	http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0209/TFP_study_20070330.pdf
OEB – Power LDCs (2008-2012)	Supplemental Report of the Board	19 years (1988-2006)	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf
OEB – Power LDCs (2013)	Empirical research in support of incentive rate setting in Ontario : Report to the Ontario Energy Board	10 years (2002-2011)	http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/PEG_Report_to_OEB_4Gen_%20IR_20130531.pdf
ENMAX (Later approved by AUC)	ENMAX Power Corporation for its 2007-2016 PBR Plan*	4 years (2001-2003)	Please refer to AUC website, application No. Application No. 1550487. Appendix 3.

Prepared for	Title of study	Sample period	Link
FERC	Docket No. RM10-25-000 - Five-Year Review of Oil Pipeline Pricing Index	5 years** (2004-2009)	http://www.ferc.gov/industries/oil/gen-info/pipeline-index/RM10-25-000.pdf
SDG&E	Productivity research for San Diego Gas and Electric (SDG&E)	10 years (1999-2008)	https://www.sdge.com/sites/default/files/regulatory/Exh%20SDG&E-44%20M_Lowry_Productivity.PDF

* 2001-2003 study was based on a sample of distribution utilities in New Zealand.

** The time period of analysis includes a base year, 2004, and five points of change, 2005-2009, from which to measure cost changes against the base year.

18.2 What was the length of the time period used in the TFP study in which the Alberta Utilities Commission relied when it established its X Factor in Decision 2012-237?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.8.2. This response is identical to the FEI response to that IR.

The AUC adopted the NERA's TFP study which was based on a set of data from 1972 to 2009 (38 years). However the AUC also acknowledged that "the majority of other parties recommend a substantially shorter period". The AUC stated that this long period is justified due to the use of volumetric output measures: "Because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns". The AUC also recognized that when an output measure other than volumetric output is used, "the resulting TFP may be less sensitive to the choice of start and end dates".

18.3 Why has FBC selected the shortest time period, 5 years, for the calculation of its X-Factor? Provide support from the economics literature for using a short time period such as 5 years for a TFP study.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.9.3..

Please refer to the responses to BCUC IRs 1.17.1 and 1.17.2.

19.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

19.1 Please explain precisely which capital projects are included in the PBR plan under the I-X mechanism and which capital projects would be excluded from the I-X mechanism under FBC's proposals. Provide examples for clarity.

<u>Response:</u>

Capital expenditures include both regular capital expenditures (Growth, Sustainment, and Other) and major projects (generally those approved by way of CPCN applications). As explained in Section B6.2.5 from Exhibit B-1, the use of formula based calculations (including the I-X mechanism) are limited to regular capital expenditures. Examples of regular capital expenditures include:

- All Plants Concrete and Structural Rehabilitation (sustainment);
- Station Urgent Repairs (sustainment);
- Transmission Lines Rehabilitation (sustainment);
- Distribution Lines Condition Assessment (sustainment);
- SCADA Systems Sustainment (sustainment);
- Huth 8 kV Transformer Upgrade (growth)
- Reconductor 52 and 53 Lines (growth)
- New Connects System Wide (growth)
- Distribution Unplanned Growth (growth)
- Vehicles (other)
- Furniture and Fixtures (other)

The major capital projects (generally approved by way of CPCN Applications) excluded from the I-X mechanism in the 2014 – 2018 PBR Plan are provided below:

- Advanced Metering Infrastructure;
- PCB Compliance – Substations;
- Kelowna Bulk Transformer Addition;
- Grand Forks Transformer Addition;
- Ruckles Substation Upgrade;

- New Central Okanagan Substation;
- Grand Forks to Warfield Fibre Installation;
- Corra Linn Spillway Concrete and Spill Gate Rehabilitation
- Upper Bonnington Units 1,2,4 Refurbishment; and
- Kootenay Long Term Facilities Strategy.

19.2 How did FBC decide on this framework for handling capital costs under its PBR plan? Are there any precedents in North America for such a framework?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.10.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

This response augments the response to BCUC IR 1.19.1.

B&V states that the simple logic of TFP analysis requires that capital-related issues be addressed differently under PBR and even under cost of service regulation where regulators have recognized the importance of timely cost recovery for the capital associated with infrastructure replacement. Numerous jurisdictions provide for separate recovery of these infrastructure costs based both on legislative mandates and regulatory decisions even using cost of service regulation for other costs.

Under PBR, the OEB has adopted three separate PBR plans designed to directly address the issue of capital recovery. Enbridge has proposed a similar customized PBR Plan with separate capital updates for the later years of the plan. There is no practical way to capture CPCN capital projects under the PBR Plan, which is reflected in the previous PBR plans for FBC. The 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 as explained in Section B of the Application. For a further discussion of this issue, see for example the section, Treatment of Capital Expenditures, in the "Incentive Regulation Design" presented to the AUC workshop by Paul Carpenter of the Brattle Group.

19.3 What percentage of its capital spending during the PBR term does FBC estimate will be included under the I-X PBR mechanism?

Response:

FortisBC estimates that approximately 60 percent of its capital spending (based on preliminary estimates of CPCN project costs) during the PBR term will be included under the I-X PBR mechanism.

The components of capital expenditures that are subject to the I-X formula are the formulaic capital expenditures identified at line 15 of Table B6-7 and capitalized overheads, which are a function of O&M Expense, the majority of which is also determined by the I-X formula.

Capital Expenditure Parameters		2014	2015	2016	2017	2018	Remarks
Formulaic Capital		43,534	44,764	46,012	47,309	48,630	Refer: Exhibit B-1, Pg 58, Table B6-7
Add Capitalized OH (20% of O&M)		12,277	12,349	12,192	12,476	12,660	Included as it is a PBR Component
Subtotal-1: Formulaic Capital (Subject to I-X)	**A**	**55,811**	**57,113**	**58,204**	**59,785**	**61,290**	
Add Capital Tracked Outside of the Formula							
Pension & OPEB (Capital Portion)		6,396	5,952	5,508	5,133	4,826	Refer: Exhibit B-1, Pg 58, Table B6-7
PCB Compliance - Substation		6,062					Refer: Exhibit B-1, Pg 58, Table B6-7
Advanced Metering Infrastructure Project		16,765	18,233	583	741	604	Refer: Exhibit B-1, Pg 58, Table B6-7
Subtotal - 2	**B**	**29,223**	**24,185**	**6,091**	**5,874**	**5,430**	
Add Other Overheads							
Direct Overhead		5,000	5,000	5,000	5,000	5,000	
AFUDC		1,375	427	362	208	389	
Subtotal - 3	**C**	**6,375**	**5,427**	**5,362**	**5,208**	**5,389**	
Grand Total -1	**D=A+B+C**	**91,409**	**86,725**	**69,657**	**70,867**	**72,110**	Reconciliation for Year 2014: Exhibit B-1, Pg 284, Exp., Lines 65+71
Add Capital Tracked Outside of the Formula							
Total CPCNs (Unloaded)		6,603	7,993	10,577	36,057	29,440	
Total CPCN Overheads	**E**	291	355	1,307	3,877	2,383	
		6,894	**8,348**	**11,884**	**39,934**	**31,823**	
Grand Total -2	**F = D+E**	**98,303**	**95,073**	**81,541**	**110,801**	**103,933**	
% Subject to I-X	**% A/F**	**57%**	**60%**	**71%**	**54%**	**59%**	Average: 60%

20.0 Reference: Exhibit B-1, pp. 44-49

X–Factor Estimation

FBC states "FBC proposes a fixed X-Factor of 0.5 percent (inclusive of any stretch factor) for its 2014 PBR Plan." (Exhibit B-1, p. 49)

20.1 Please provide the value of the stretch factor that FBC included in the X-Factor of 0.5 percent.

Response:

The difference between the average TFP calculated by B&V in Appendix D-2 of minus 5.5% and the proposed X-Factor of 0.5%, would result in an implied stretch factor of 6%. No explicit stretch factor value has been calculated because of the fact that CPCN values are not included in the PBR, whereas in the TFP study the TFP value reflected all capital related to transmission, distribution and general plant for the utilities in the study. The nature of the available data does not permit the study to exclude CPCN types of projects from the calculation of the TFP, so it is not possible to calculate an explicit stretch factor.

"For example, Ontario's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study conducted by the OEB's consultant was estimated at 0.72 percent, while the most recent study prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative TFP growth of -0.05 to -0.03 percent." (Exhibit B-1, p. 47)

20.2 Provide the Ontario Energy Board (OEB) stretch factor for the "Cohorts" most similar to FBC and reasons for the selection.

Response:

There is no theoretical basis for including FBC in the cohorts developed by the OEB because the utilities are not similar.

> "Given the lack of a centralized database of Canadian utilities and the different reporting requirements among Canadian jurisdictions, B&V compiled TFP data on 72 US-based electric utilities. U.S. data has been used in other Canadian jurisdictions as well, and is appropriate because of common systems, technologies, and operating methods." (Exhibit B-1, p. 48)

20.3 Please discuss any disadvantages of applying US data to FBC's operations.

Response:

B&V provides the following response.

There may be differences between the particular circumstances of US and Canadian electric utilities when compared individually. Those same differences would remain when comparing Canadian to Canadian or US to US electric utilities. In looking for a measure of the central tendency of Total Factor Productivity, these differences are subsumed by the diversity of the sample size. Thus the TFP analysis measures the impacts of productivity based on the same types of systems, using the same types of inputs and technologies and operating under the same overall standards. The AUC recognized that the use of US data was reasonable as well. Finally, in addition to the absence of uniform data for the Canadian electric utilities, the actual sample of comparable size investor owned utilities would be limited because of the limited number of IOU integrated electric utilities in Canada and most of those are in the Fortis family of companies. As a result the options to use another sample are limited at best thus making the choice of US data appropriate.

21.0 Reference: Exhibit B-1, p.50

Determination of FBC Rates

21.1 What percentage of FBC's total revenue requirements will be determined under the I-X framework of its PBR plan during the five years of the PBR plan?

<u>Response:</u>

Approximately an average of 18% of FBC's total revenue requirements will be determined under the PBR plan during the five year period of 2014-2018. A high level analysis is shown in the Table below.

REVENUE DEFICIENCY	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Average 2014-2018	Remarks
Revenue Requirements determined under the PBR Framework:							
O&M Expense	61,386	61,744	60,960	62,378	63,302	61,954	Determined by PBR
Capitalized Overhead	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)	(12,391)	Determined by PBR
Income Taxes	(6,181)	(7,362)	(6,584)	(5,813)	(5,100)	(6,208)	Impact as determined by PBR
Cost of Debt	558	2,613	4,880	6,713	8,663	4,685	Component determined by PBR (Plants in Srvice)
Cost of Equity	1,309	4,554	7,088	9,100	11,009	6,612	Component determined by PBR (New Plants in Srvice)
Depreciation and Amortization	-	4,068	7,536	9,869	12,298	6,754	Component determined by PBR (New Plants in Srvice)
Total	**44,794**	**53,269**	**61,689**	**69,772**	**77,511**	**61,407**	
Revenue Requirements not determined under the PBR Framework:							
Power Purchases	87,814	116,380	134,204	136,716	140,322	123,087	Load Driven - Not determined by PBR
Water Fees	10,057	10,532	10,479	10,688	10,902	10,532	Generation Driven - Not determined by PBR
Wheeling	5,224	4,856	4,952	5,050	5,208	5,058	Load Driven - Not determined by PBR
Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)	(7,713)	Not determined by PBR
Property Taxes	15,903	16,329	16,612	16,975	17,290	16,622	Assumed Not determined by PBR for simplicity
Income Taxes	15,422	12,101	10,479	12,631	14,643	13,055	Impact in the absense of PBR Components
Cost of Debt	42,050	39,129	38,045	36,831	35,198	38,250	Component not determined by existing plants and services
Cost of Equity	43,590	41,456	39,854	38,429	36,830	40,032	Component not determined by existing plants and services
Depreciation and Amortization	57,773	51,999	50,681	50,688	50,579	52,344	Component not determined by existing plants and services
Flow Through Adjustments	(14,207)	-	-	-	-	(2,841)	Assumed Not determined by PBR for simplicity
Rate Smoothing	22,567	(2,430)	(10,112)	(7,100)	(2,925)	-	Assumed Not determined by PBR for simplicity
Total	**278,611**	**282,722**	**287,414**	**293,154**	**300,229**	**288,426**	
Total Revenue Requirement:	**323,405**	**335,990**	**349,102**	**362,926**	**377,740**	**349,833**	
Revenue Requirements determined under the PBR Framework as a % of Total Revenue Requirement:	**14%**	**16%**	**18%**	**19%**	**21%**	**18%**	

22.0 Reference: Exhibit B-1, pp. 50-52

2013 Base O&M

FBC proposes a positive adjustment to 2013 Base O&M costs of $3.238 million for 2013 Adjustments (Table B6-4: 2013 Base O&M, page 51, line 8). FBC states that this is "actual incurred 2013 'non-controllable' O&M that is held in deferral accounts in 2013" (p. 50, lines 34-35).

22.1 Please clarify that these deferral accounts will not be used in the PBR plan after 2013 and that the deferral account revenues will now be included in Base O&M rates and subject to the I-X formula? If this is not the case, how are the deferral accounts handled under the PBR framework proposed by FBC?

Response:

The $3.238 million adjustment includes 2013 expenses related to Mandatory Reliability Standards (MRS), Provincial Sales Tax and Pension/OPEB.

The MRS adjustment amount of $0.9 million represents an adjustment to the 2013 approved O&M which is required to maintain full and auditable compliance with the BC MRS program. Once this adjustment is included in Base O&M, it will be subject to the I-X formula.

The PST adjustment reflects the full-year impact on O&M expense of the elimination of the HST. Once included in Base O&M, this amount will also be subject to the I-X formula. The proposed Tax Variance Deferral Account will be utilized during the PBR period to capture any future changes in tax legislation; however, FBC is not anticipating any specific additions related to PST in this deferral account during the PBR period.

The deferral account covering Pension/OPEB will also continue to be utilized throughout the PBR period. FBC will reforecast the amounts at each annual review to be included in the O&M for rate setting purposes (added on to the formula O&M as shown in Table B6-5). As is the case for Insurance fees, the variances between the amounts included in O&M for rate setting and the actual amounts incurred will be captured in deferral accounts for amortization in future rates.

In this fashion, Pension/OPEB and insurance fees effectively become "Flow-Through items" as discussed on Page 60 of the Application, a mechanism used for non-controllable costs to ensure that customers pay actual costs in circumstances where the Utility does not control the level of expenditures. For this reason the Pension/OPEB and Insurance fees are tracked outside of the PBR formula.

In Table B6-5 on page 53 of the Application, the 2013 Base O&M, inclusive of Pension/OPEB and Insurance, provides the appropriate "base" for the 2014 through 2018 O&M expense. In lines 3 and 4, Pension/OPEB and Insurance are removed from the 2013 Base O&M to arrive at the 2013 Base amount that will be subject to the PBR formula. (Since there are no AMI-related costs included in the 2013 Base, there are no amounts to remove.)

Beginning in 2014, the O&M that is subject to the formula is then escalated, and the full amount of Pension/OPEB and Insurance along with the O&M impact of AMI is added back to the formulaic O&M (lines 19 – 23) to arrive at the Total O&M Under PBR which is used to set rates. This demonstrates the intended treatment that non-controllable items are not subject to the I-X formula, but rather included on a forecast basis in Total O&M for rate setting purposes. Note that the amounts shown in Table B6-5 for Pension/OPEB and Insurance are forecasts at this point in time and will be updated each year as part of the Annual Review process. This treatment is consistent with the 2007 PBR Plan in which certain costs, including Pension/OPEB, were added to the formula-derived portion of O&M Expense.

A similar approach is taken with the capital formula determination.

Relate this response to Table B6-5, Forecast O&M Formula Results, on page 53, lines 2-5 and 20-23 which shows three categories of O&M expenses being tracked outside of the formula.

22.2 If these three deferral accounts are eliminated at the beginning of FBC's PBR plan, what changes, if any, would FBC recommend to its proposed PBR plan?

Response:

The PBR Plan recognizes Pension/OPEBs and Insurance as material examples of "non-controllable' expense. B&V, addressing "non-controllable" costs on page 68, states

> "…it is important to allow full recovery of these costs under a PBR plan, as the costs – being outside the control of management – are by definition prudently incurred costs of providing utility services that should be recovered from customers in the normal course."

The deferral account treatment for Pension/OPEBs and Insurance is one of many factors that combine to form the risk/reward profile of the PBR and the assignment of this profile between customers and the shareholder. FBC views the risk/reward profile presented in the PBR as being fairly assigned between customer and shareholder. If these deferral accounts were eliminated at the beginning of the PBR, FBC would view this as a significant adjustment to the risk/reward profile.

At this time FBC does not expect any additional deferral amounts related to MRS or PST during the PBR Period, for the reasons explained in response to BCUC IR 1.22.1.

23.0 Reference: Exhibit B-1, pp. 52-54

2014-2018 O&M

23.1 Please explain why FBC chose a revenue cap, which involves forecasting the number of customers in its annual review (page 52) rather than a revenue-per-customer cap which would avoid the need for this forecast? Provide a detailed explanation, including references to any literature or to other PBR plans for gas distribution or electric distribution companies.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.13.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC and cross-references.

The premise of this question is incorrect. Revenue cap and revenue per customer cap approaches both involve forecasting the number of customers for rate-setting purposes. FBC's approach is based on its successful 2007 PBR Plan and is a building block version of the revenue cap model. Please refer to the response to BCUC IR 1.25.1 for other PBR examples of the building block approach.

24.0 Reference: Exhibit B-1, pp. 52-54 and pp. 56-59

2014-2018 O&M and Capital

24.1 Explain why FBC chose a revenue cap rather than a price cap for its PBR plan for both O&M and capital.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.14.1.

FBC has based the 2014 PBR Plan on its successful FBC 2007 PBR Plan with respect to use of the same revenue cap approach. As stated on page 23 of the Application "The success of FBC's 2007 PBR Plan provides a strong basis for going forward with a similar model for the proposed PBR. The model approved for use by FBC between 2007 and 2011 provided a flexible framework of incentives that allowed FBC to capture efficiencies for the long-term benefit of customers." This proposal recognizes that a revenue cap provides symmetrical risk sharing related to volumes where FBC promotes DSM and other factors cause variations in sales.

Therefore in order for FBC to have an opportunity to earn its allowed return on and of its investments it is essential that the Company's PBR plan is designed in a way that the risk of use rate decreases is mitigated. The revenue cap will provide a framework for incenting the utilities to seek additional productivity gains while protecting them from exogenous demand variation risks.

25.0 Reference: Exhibit B-1, pp. 52-54

2014-2018 O&M

On page 52, after line 24, FBC presents the formula that it proposes to use for O&M expenses in its PBR plan.

25.1 Explain why FBC chose to treat O&M and capital expenses separately rather than combined into total revenue that could be indexed with the I-X formula? Is there justification in the literature or with other North American precedents for this approach?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.15.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC..

The literature refers to this approach as the building block approach. This approach has precedent in the prior approved FBC PBR plans as well as other plans and proposals in other jurisdictions. The building block approach provides a better framework for forecasting the costs using PBR formulas since more relevant cost drivers can be used for forecasting the capital and operating expenditures rather than using one cost driver for total expenditures. In addition, the building block approach will continue to give the regulator some ability to monitor the capital and operating expenditure, while under a Totex approach the regulator has little control over how the utility allocates costs between Opex and Capex and can only approve the total expenditure.

Please refer to FBC's response to BCPSO IR 1.10.3 for additional examples of building block plans. Also please see PBR Section B page 30 where the concept is discussed in detail.

25.2 Given the revenue cap for O&M expenses, how does FBC ensure that the X-Factor and I-Factor are relevant for O&M expenses and not for the overall expenses of the company? Similarly, how does FBC ensure that the X-Factor and I-Factor are relevant for capital expenses considered apart from O&M expenses? Relate this response to Table B6-5, Forecast O&M Formula Results, on page 53 that shows the forecasted I and calculated X being used for O&M expenses. Similarly, also relate this response to Table B6-7, PBR Capital Formula Inputs and 5-Year Forecasts, on page 58.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.15.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

There is no difference between FBC's proposed building-block approach and the combined (or Totex) approach in this regard since FBC's I-X mechanism is applied to both Opex and Capex, similar to the Totex approach. The proposed X-Factor is based on total factor productivity (which includes both capital and operating expenditures) and a stretch factor, with the assumption that the I-X mechanism is applied to both Opex and Capex. The same reasoning is applicable to the I-Factor in that the inflationary influences apply to the total expenditures so it is appropriate to apply the same I-Factor to both Opex and Capex because they represent the total expenditures In addition, one of FBC's stated objectives is that "The PBR plan should be easy to understand, implement and administer…" and using the same I-X mechanism for capital and operating expense helps to achieve this.

26.0 Reference: Exhibit B-1, pp. 52-54

2014-2018 O&M

The formula after line 24 on page 52 includes the average number of customers, which is forecasted.

26.1 Is there a true-up for this forecast? Explain in detail why or why not, the justification for this, and the resulting incentives consequences. Relate this response to the statement on page53, lines 12-15 that "(t)he O&M allowed under PBR will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers[,] composite inflation rates, and those items tracked outside of the formula, for the upcoming year." This statement suggests that the number of customers is re-forecasted but not trued up. Is this correct? Please explain in detail the justification for this approach.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.16.1.1. This response is similar to the FEI response, however some minor differences were necessary in order to respond appropriately for FBC.

FEI and FBC used the term "true up" in describing the PBR proposal since this terminology was used in FEI's 2004 PBR to describe what is being contemplated here. The true-up features for the PBR I-X formulas pertain to the cost drivers only (i.e. average number of customers and service line additions). However, on reflection, a better way to describe the process would be a re-forecast using the latest available information on the cost drivers in the PBR formulas (i.e., actual average customers and service line additions when these quantities are known).

The term "true up" for the O&M formula was used in relation to adjusting for actual customer growth in Table B6-1 and again in Table B6-10. In fact, the re-forecast number of customers to be used each year in the Annual Review will update prior year customer counts for actual customer growth[12] and a new forecast of customer growth for the coming year. As indicated above, this process is the same treatment that was applied for customer counts in the 2007 PBR.

[12] Since the Annual Review will occur in the fall of the year actual customer growth for the full year will not be known but a projection to year-end will be made. Any small variances in customer count (positive or negative) between the projected and actual numbers will be trued up in the following year.

27.0 Reference: Exhibit B-1, pp. 51-54

2014 - 2018 O&M – Average Customers/Capacity

FBC states "As a result, B&V believes it is appropriate to use customers [average customers] as a reasonable proxy for the capacity variable in the formula." (p. 53)

27.1 Please explain how capacity relates to average number of customers, average demand/customer, average system load-factor, and capacity.

Response:

B&V provides the following response:

Electric system costs are driven by both customers and capacity, albeit with different definitions for capacity for different components of the system. Since the capacity variable is an elusive value, the formula must include a value that is readily available in the data. Customer count is a reasonable proxy for capacity because customer count explains directly a significant portion of O&M on its own and relates indirectly to the need for capacity in distribution, transmission and generation.

Average demand per customer (defined as annual energy divided by 8760 or 8784 hours per year) has no relationship to any capacity measure that is a cost driver for the utility. Total capacity is a function of peak demand plus required reserves.

System load-factor also has no relationship to capacity except to the extent that higher load factors may increase the reserves required to perform annual generation unit maintenance. Even then it provides no information related to capacity associated with transmission and distribution. Simply, average demand says nothing about coincident and non-coincident peak loads that impact system capacity costs. Further, it is the design capacity requirements that cause capacity related costs, not some actual peak load that fluctuates with weather and other operational factors. In fact, peak load is not even the total demand on capacity for a utility system because scheduled maintenance, forced outages, seasonal de-ratings and partial outages all create demand on the available capacity for generation and in some cases for other components of the system. With respect to other components of the system, design day requirements reflect less diversity of loads as system components are closer to customers. This means that customer transformers must have more aggregate capacity than substations and so forth.

Based on this discussion, the result is that customer count becomes a reasonable proxy for the capacity variable in the formula.

27.1.1 Please provide the average demand factor for the FBC electrical system.

Response:

FortisBC provides the following table in response to the BCUC IR 1.27.1 series of questions.

	Actual	Forecast					
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Gross Energy Load (GWh)	3422	3496	3519	3537	3554	3572	3596
Average Demand (MW)	390	399	402	404	405	408	411
Peak Demand (MW)	723	743	750	756	761	767	772
Load Factor	0.54	0.54	0.54	0.53	0.53	0.53	0.53

Energy and peak values are taken from Table C1-1 of the Application and are a normalized and after-savings forecast. The Average Demand values are calculated as (Gross Energy Load / hours per year). The Load Factor is calculated as (Average Demand / Peak Demand).

27.1.2 Please provide the peak demand factor for the FBC electrical system.

Response:

Please refer to the response to BCUC IR 1.27.1.1.

27.1.3 Please provide the load factor for the FBC electrical system.

Response:

Please refer to the response to BCUC IR 1.27.1.1.

27.1.4 Since very few electrical components are operated at 100 percent capacity, please provide the percent permissible electrical loading of the FBC electrical components according to FBC's best practices in terms of peak and average demand.

Response:

FBC equipment sizing is based on peak demand, not average demand. Device ratings are selected such that that equipment loading does not exceed the nameplate rating in normal operations when considering the projected winter and summer load forecasts.

27.1.5 Please discuss how the incremental change in the average number of customers relates to the electrical system capacity.

Response:

Incremental changes in the number of customers is related to system capacity in the following ways:

1. Customer additions result in load growth throughout the service area. However, the distribution of these additions varies from year to year. If customer additions occur predominantly in one area, then the probability of capacity upgrades in that area are more likely compared to if the customer additions are spread evenly throughout the service territory. Every customer addition adds new capacity requirements to the system because it adds new transformers at the local level, added conductor and related facilities to reach the customer, impacts the required capacity at a substation that serves the area and ultimately impacts the transmission system. These impacts are cumulative over time and eventually existing facilities are inadequate to serve the load and must be reinforced.

2. Since transmission and distribution assets are costly to install, they are sized to meet the expected load growth over their life at the time of initial installation on the assumption that ongoing load growth will consume the remaining capacity. Eventually however, all surplus capacity is consumed and a capacity upgrade is then required. A salient example of this is the recently completed Okanagan Transmission Reinforcement (OTR) project. The bulk transmission system in the Okanagan area remained essentially unchanged for many years and was able to absorb year-over-year incremental load growth. However, eventually a "tipping point" was reached where new load growth

resulting from both customer additions and added loads from existing customers exceeded system capacity and as a result, FBC was required to implement the OTR project. A similar example occurred in another portion of the system approximately 10 years prior when FBC constructed the Kootenay 230kV System Development Project.

In the aggregate and in the longer term, localized capacity upgrades that are required by both new customers and new loads for existing customers through the system tend to average out. On this basis, FBC considers that customer growth (and hence the average number of customers) is a reasonable proxy for capacity.

27.2 Is O&M more closely related to the quantity of assets (Plant in Service) to be maintained? Please explain why FBC does not use Plant in Service instead of the average customers as the adjustment ratio?

Response:

Under PBR the issue is providing one consistent set of factors. O&M increases as customers are added because of the additional plant in service. Using one consistent set of factors is reasonable and avoids all of the issues related to multiple different cost drivers. Simply, there would be different drivers for O&M based on each different type of plant because plant has different operating characteristics. The added complexity of multiple drivers would far outweigh any perceived benefit.

27.2.1 Please explain why customers are a principal driver for costs when the customers only represent load and not capacity in the base year of 2013.

Response:

Customers do drive capacity in the base year of 2013 as the system is designed to serve the peak hour capacity requirements for customers including coincident and non-coincident peaks. Since capacity is not easily transparent, it is appropriate to use customers as a proxy.

27.2.2 Please explain why capacity is not easily measured and is lacking in transparency.

Response:

B&V provides the following response.

First, there is no single measure of capacity as noted in BCUC IR 1.27.1. Consider the issues of measuring transmission capacity. There are three different functions for transmission capacity- moving generation from the plant to the bulk transmission system, moving power from the bulk system to the distribution system and the bulk delivery portion of the system that may move not only own generation but exports, imports and power through the system. These three components of transmission may all have different capacity measures and in addition there may be generation units such as units for area protection that must run to satisfy transmission constraints. Having recognized these three functions, it is not easy to identify the design capacity of any of the components and they may vary by season.

Second, this problem is compounded when it comes to measuring the capacity for the distribution system because the number varies as one moves from substation to meter along the system. While it is reasonable to measure substation capacity by MVa of installed transformers, that estimate is not an estimate of the capacity required on various components of the distribution network. Those estimates vary with loads and other issues such as power factor and the need to use capacitors for the system.

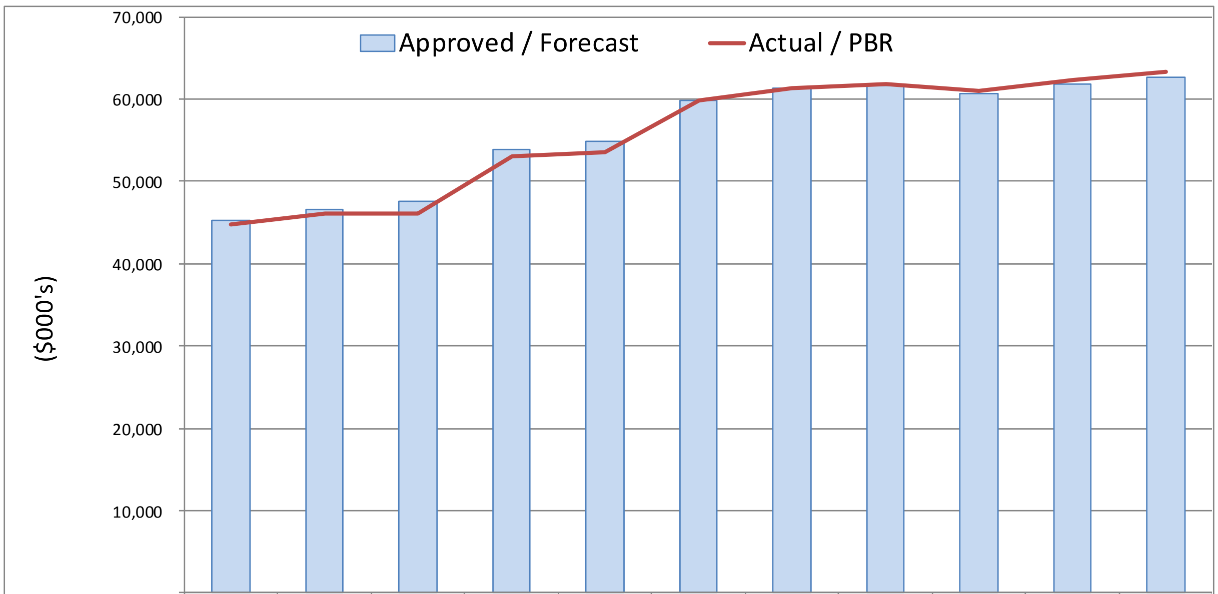
Third, for items such as poles there are a number of factors that impact the choice of a pole such as minimum clearances but also items such as the size of the transformer mounted on the pole. This means that the installed cost of a transformer will vary with the type of pole required and there must be a pole for the transformer(s) as a unit except in the case of underground systems.

The estimates of capacity lack transparency because there is no practical way for a third party to verify the estimated capacity even of the substation transformers much less line transformers. Estimates of capacity would rely on the utility continuing property records at best and there would be thousands of entries. This is not efficient or cost effective.

27.3 Using the previous five years data, provide a table and graph of the actual O&M expenditures and for the PBR term (using the proposed formula) in a format similar to Figure B6-2 to demonstrate the ability to forecast O&M expenditures.

Response:

The table below provides the previous five years data of actual and approved O&M expenditures with 2013 and the PBR term data.



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Approved / Forecast	45,310	46,573	47,645	53,885	54,843	59,848	61,375	61,612	60,608	61,889	62,634
Actual / PBR	44,725	46,017	46,148	53,076	53,543	59,848	61,386	61,744	60,960	62,378	63,302

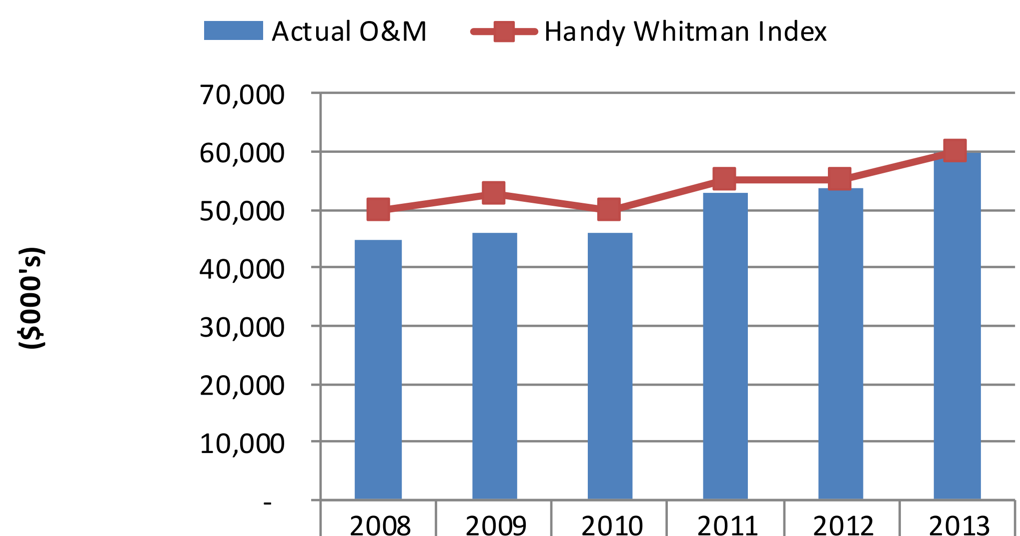
27.4 Using the previous five years data, provide a table and graph of the actual O&M expenditures adjusted to 2013$ using the Handy Whitman Index in a format similar to Figure B6-2 to demonstrate the ability to forecast O&M expenditures.

Response:

The Handy Whitman Index is used for the valuation of utility construction assets, the data therefore is not applicable to indexing O&M costs.

However, the data and table have been provided below which has applied an equal one third of the indices from Hydro Production Plant, Transmission Plant, and Distribution Plant.

In addition, the Company notes that this analysis, not only incorrectly applies the Handy Whitman Index, but also ignores items like Commission ordered changes in accounting of certain cost items. The comparison of historical to current data is therefore flawed logic.



	2008	2009	2010	2011	2012	2013
Actual O&M	44,725	46,017	46,148	53,076	53,543	59,848
Handy Whitman Index	49,941	52,525	49,883	55,321	54,995	59,848

28.0 Reference: Exhibit B-1, pp. 52, 53, and 55

Proxy for Capacity

The Application states "B&V considers that linking O&M to the number of customers is appropriate. B&V has noted in its PBR Report and TFP Report that customers and capacity are the principle drivers for costs. For O&M, a number of the specific costs are driven by number of customers. Other costs are driven by capacity. The 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. It effectively adds an estimate of additional O&M expense associated with system growth to the plans revenue adjustment." (Lines 3-10, p. 53)

FBC states, "As in the 2007 Plan, the PBR formula FBC proposes to apply to the O&M is tied to the average number of customers." (p. 52)

FBC states "FBC has included in its PBR formula the following three categories of regular capital expenditures – growth, sustainment and other capital" and "…the formula-based capital expenditures will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers…" (p. 55)

28.1 Assuming that capacity is more closely related to gross load served, $\left(\frac{GWh_{(t)}}{GWh_{(t-1)}}\right)$, please explain by customer class why the incremental change in the average number of customers was chosen as the proxy for capacity.

Response:

The premise for this question is incorrect. Please refer to the response to BCUC IR 1.27.1.5 as to how an incremental change in the number of customers relates to capacity. FBC has not distinguished between customer classes for this purpose as the capacity provided by system infrastructure is typically shared between multiple customer classes.

28.2 Assuming that some O&M and capital expenditures (i.e. generation expenditures) are more closely associated with incremental gross load growth than incremental customer growth, please provide a list of those O&M and capital expenditures that are more closely related to incremental gross load growth.

Response:

Please refer to the response to BCUC IR 1.27.1 which explains why customer growth is a reasonable proxy for capacity when determining the cost driver for a PBR formula.

28.2.1 Please discuss how the incremental gross load growth and the incremental customer growth affect FBC's generation expenditures.

Response:

Customer and load growth do not affect generation expenditures directly, but affect O&M Expense and Capital expenditures in aggregate. The proposed PBR formulas are applied to Base O&M and Base Capital at the aggregate levels, not at the functional level.

FBC identified five principles in the development of its proposed PBR Plan, which are identified at page 39 in Section B6 of the Application. Principle 5 reads "The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time."

The application of the PBR formulas at the aggregate level for O&M and capital yields a result that is easy to understand, implement and administer. While it would be possible to increase the granularity of the formula-driven components of the PBR Plan, this would also increase the complexity of the mechanism unnecessarily.

28.3 Are the forecasted gross load numbers in Exhibit B-1-1, Appendix E2, p. 1 for average load or peak load?

Response:

In utility practice, the term "load" can refer to energy requirements (MWh) or peak demand (MW). The forecasted gross load numbers in Exhibit B-1-1, Appendix E2, p. 1 are the expected annual energy requirements (MWh). They are neither for average demands nor for peak demands (MW).

28.3.1 If the numbers are the average loads, please provide the peak loads.

Response:

The numbers in Exhibit B-1-1, Appendix E2, Section1, Table 1.1 are the expected annual energy requirements (MWh). They are neither for average demands nor for peak demands (MW), for further clarification please refer to the response to BCUC IR 1.28.3. The normalized and forecast peak demand can be found in Exhibit B-1, Section C-1, Figure C1-13.

28.4 Please provide a table similar to Table E2-5: Comparisons of Forecasting Methods for the Residential Customer Count without City of Kelowna that shows the Customer Count with City of Kelowna for all customer classes.

Response:

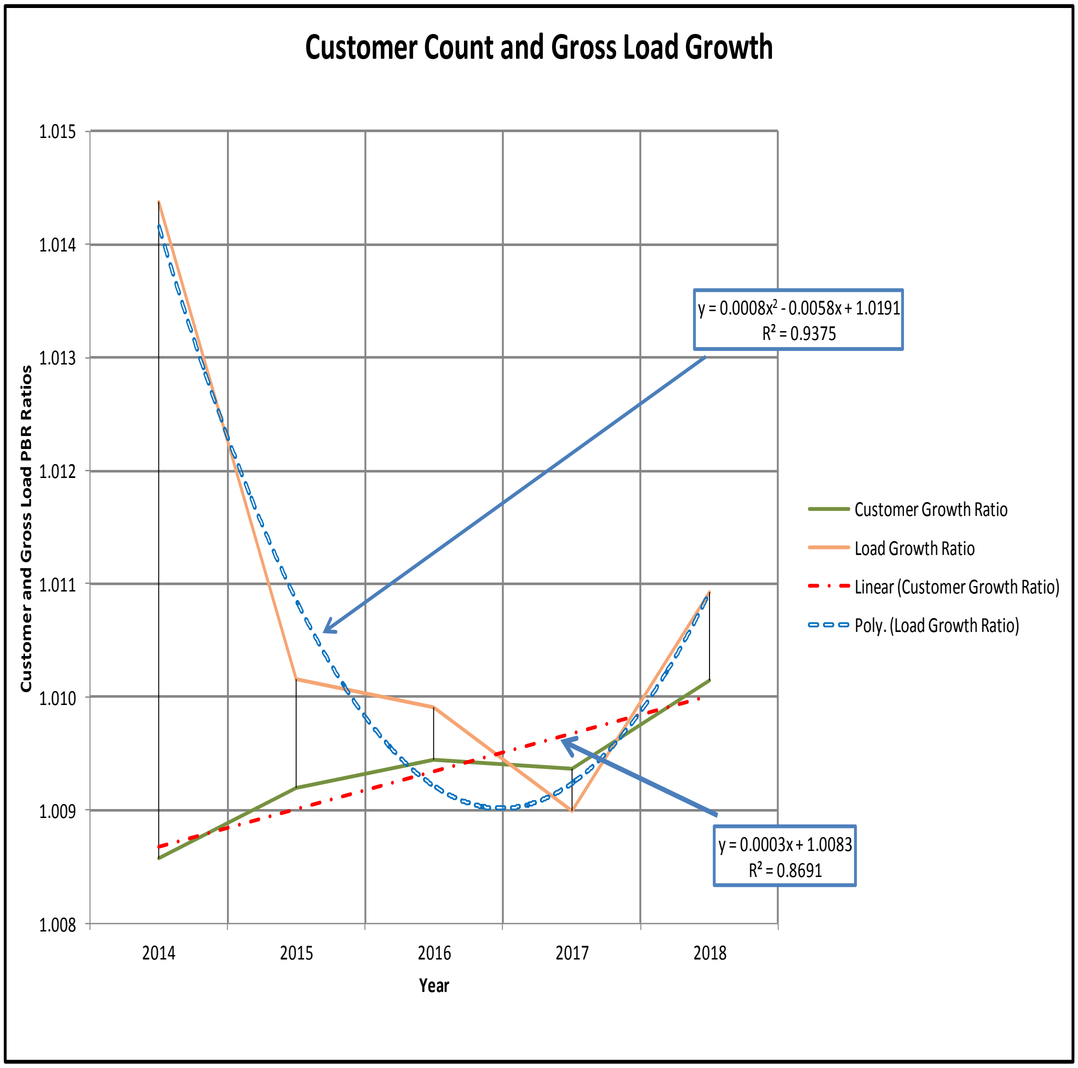
After the CoK integration in April 2013 the CoK residential customer count was forecast to grow at a rate of 1%. The CoK commercial growth was estimated at the 5-year average while the industrial count was assumed to remain constant after the integration. The actual and forecast customer counts for the CoK, are provided below. Prior to the 2014 PBR application, CoK was an individual wholesale customer and hence the Company did not forecast its customer count per load classes. Therefore, methodological comparisons like those shown in Table E-5 are not available for CoK.

	CoK Year-end Customer Counts			Growth of CoK Year-end Customer Counts		
Year	Residential	Commercial	Industrial	Residential	Commercial	Industrial
2007	11,891	1,292	12			
2008	12,424	1,324	12	533	32	-
2009	12,831	1,345	12	407	21	-
2010	12,852	1,335	12	21	(10)	-
2011	13,048	1,362	12	196	27	-
2012	13,067	1,362	12	19	-	-
Forecast						
2013	12,972	1,572	9	-95	210	-3
2014	13,102	1,585	9	130	13	-
2015	13,233	1,598	9	131	13	-
2016	13,365	1,610	9	132	13	-
2017	13,499	1,623	9	134	13	-
2018	13,634	1,636	9	135	13	-

By adding the forecast numbers in the table above to the counts without CoK, FBC obtained the following customer counts which include CoK.

		Residential Customer Count with CoK				Other Customer Counts with CoK					Growth of Other Customer Counts with CoK				
Year	Actual Year-end Customer Count	2012-2013 RR Method	2014-2018 PBR Method	2012-2013 RR Method	2014-2018 PBR Method	Commercial	Industrial	Wholesale	Lighting	Irrigation	Commercial	Industrial	Wholesale	Lighting	Irrigation
2007	105,538	103,280	105,124			12,302	50	7	1,992	1,030					
2008	107,926	108,005	108,624			12,540	48	7	1,910	1,048					
2009	109,396	109,241	110,187			12,653	45	7	1,874	1,066					
2010	110,735	110,910	110,437			12,754	47	7	1,830	1,075					
2011	111,843	112,357	111,264			12,887	48	7	1,803	1,092					
2012	112,295	113,461	112,097			13,173	51	7	1,739	1,091					
Forecast				**Growth**											
2013		113,725	112,740	1,430	445	13,589	48	6	1,742	1,091	416	-3	-1	3	-
2014		115,434	113,589	1,708	849	13,847	48	6	1,742	1,091	258	-	-	-	-
2015		117,309	114,521	1,875	932	14,114	48	6	1,742	1,091	267	-	-	-	-
2016		119,271	115,508	1,963	987	14,368	48	6	1,742	1,091	255	-	-	-	-
2017		121,223	116,544	1,952	1,036	14,576	48	6	1,742	1,091	208	-	-	-	-
2018		123,185	117,600	1,961	1,056	14,879	48	6	1,742	1,091	303	-	-	-	-

Using Exhibit B-1, Table C1-1: Actual and Forecast Year-End Customer Count (includes City of Kelowna) and Exhibit B-1-1, Appendix E2, Table 1.1 Gross [load], p. 1, the following graph has been produced showing the relationship between incremental gross load growth and incremental customer growth during the PBR term.

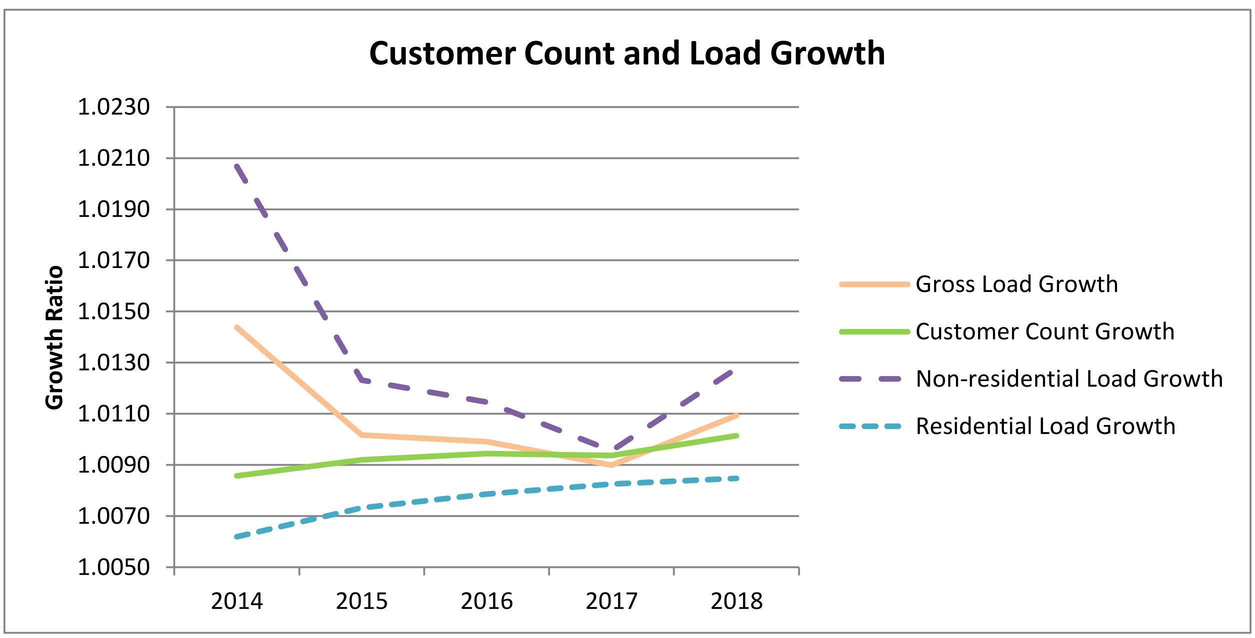


28.5 Please explain the decrease in incremental gross load (MWs) between 2014 and 2017 when there is a correspondingly steady increase in the incremental customer growth.

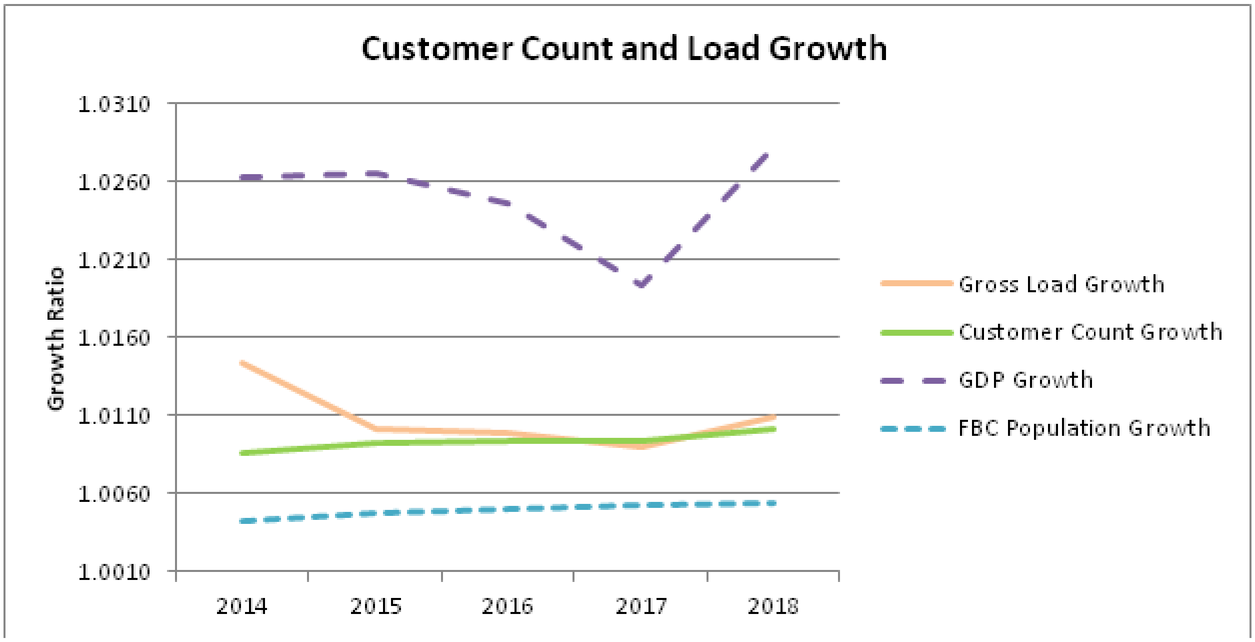
Response:

The graph as produced by the Commission above shows a significant slope for load growth ratio and also a steeper slope for customer growth rate. This visual is accomplished only by using a ratio to the third decimal place where the actual magnitude of change is amplified and exaggerated. In fact, if the same chart were to be extended to include historical data prior to 2014, the changes that are seen in the chart would be relatively minimal. As such there is very little variance in either load growth or customer growth rate to speak of when compared to the actual historical variations in growth. Despite the insignificance of the changes, the following has been prepared to address the question.

The direct total customer count growth rate is mainly determined by the residential customer count growth rate because the residential customer count accounts for 87% of the total direct count. Meanwhile, the residential load accounts for approximately 35% of the gross load and hence, the gross load growth rate is mainly determined by the non-residential classes. For illustration, the graph above is reproduced below with additional lines for the residential and non-residential before-saving load growth, which are adjusted with Q1 2013 CoK load as CoK was still in the wholesale load class in that time. It is clear that the residential load synchronizes with the total customer count growth while the non-residential load growth is in line with the gross load growth.



Note that the non-residential load is influenced by a number of factors, in particular the GDP forecast by the CBOC, while the residential customer count is determined by the FBC direct population by BC Stats. The chart below shows the movements for the gross load growth and the GDP growth, as well as for the total customer count growth and the FBC direct population growth. The gross load and the GDP growth rates are reducing until 2017 until picking up in 2018. On the other hand, the total customer count growth is steadily increasing with the increasing FBC population forecast.



28.6 Please explain why the incremental change in customer growth is increasing in a linear fashion while the incremental change in gross load is not.

Response:

The chart above over-complicates what is a relatively simple methodology. The total customer growth depends mainly on the residential growth, which is determined by the forecast population for the FBC service area (supplied by BC Stats). The short term trend appears to be linear, because BC Stats does not expect major changes in FBC's relatively small service area. Meanwhile, the before-saving gross load growth is determined by a number of factors including the FBC population forecast, the provincial GDP forecast, the wholesale and industrial customers' load surveys, and the provincial GDP growth per industry forecast. The higher number of influencing factors and the higher level of volatility associated with the provincial data made it unlikely for the overall trend to be linear.

28.7 Please explain the increase in incremental gross load (MWs) between 2017 and 2018.

Response:

The incremental increase in gross load from 2017 to 2018 is due to increase in the Commercial load. The Commercial load is based on the provincial GDP forecast from the Conference Board of Canada (CBOC), the growth rate of which is forecast to increase from 1.9% in 2017 to 2.8% in 2018 as shown in the table below. Also FBC re-forecasts on an annual basis, therefore the increase seen in 2017 to 2018 will be adjusted appropriately if necessary.

2013 – 2018 CBOC Provincial GDP Forecast

2013	2014	2015	2016	2017	2018
2.7%	2.6%	2.6%	2.5%	1.9%	2.8%

28.8 Noting that some expenditures are more closely related to incremental load growth (capacity) and customer type, please explain for those capacity-related O&M and capital expenditures how the apparent gap between incremental customer growth and the incremental gross load growth can be:

28.8.1 Explained during the term of the PBR;

Response:

Please refer to the response to BCUC IR 1.27.1 which explains why customer growth is a reasonable proxy for capacity when determining the cost driver for a PBR formula.

28.8.2 Adequately funded during the term of the PBR to prevent a potential drop in the reliability indices; and

Response:

Please refer to the response to BCUC IR 1.28.5 for clarification of the graph for this question.

The premise of this question is wrong. The funding for reliability and safety of FBC's network is not related to the gap between customer growth rate and the incremental gross load growth. Under the PBR plan, FBC's O&M and capital expenditures are calculated based on the O&M and capital formulas and the Company will have the flexibility to use the cumulative approved amounts so that the safety and reliability of system remain intact in order to deliver energy to customers safely and reliably.

28.8.3 Adequately funded during the term of the PBR to avoid potential under-funding over the PBR term.

Response:

Please refer to the response to BCUC IR 1.28.8.2.

28.9 Please provide and discuss the estimated cost differences in capital and O&M expenditure funding by year that may occur during the PBR term assuming the differences on the graph are correct.

Response:

The Capital and O&M Streams during the PBR period are a function of Customer Growth Factors (among other factors). Hence any change to the Customer Growth Factors will generate different streams of O&M and Capital.

In the above information request, two such data sets / growth % are discussed, which are used in place of the customer growth ratios to calculate the O&M & Capital Stream during the PBR period.

These data sets are:

1. Load Profile – Ref.: Exhibit. B-1-1, Appendix-E2, Table 1.1, P-1, Gross Load: Used as Scenario-1.

2. Polynomial Load Profile – Ref.: Provided in BCUC IR-1 Q28.4: Used as Scenario-2

Using the above two data sets two individual streams of O&M and Capital were calculated (including their variance from the Base Cases) as indicated in the Tables below:

O&M Parameters	2014	2015	2016	2017	2018	Remarks
Base Case O&M Stream						
% Change in Customers	0.76%	0.89%	0.93%	0.94%	0.98%	Refer: Exhibit B-1,
Total O&M Under PBR	61,386	61,744	60,960	62,378	63,302	Table B6-5, Page 53
Scenario-1: O&M Stream using Forecast Load Growth Profile for Customer Growth						
% Load Growth Profile	1.44%	1.02%	0.99%	0.90%	1.09%	Refer: Exhibit: B-1-, Appdx-E2, Table-1.1, Page-1, Gross Load
Total O&M Stream	61,748	62,186	61,448	62,855	63,861	
O&M Variance from Base Case	361	442	487	477	560	
Scenario-2: O&M Stream using Polynomial Load Growth Profile for Customer Growth						
% Load Growth Profile	1.64%	1.22%	0.96%	0.86%	0.92%	Refer: Graph proded by BCUC IR-1 Q28.4
Total O&M Stream	61,855	62,408	61,658	63,049	63,958	
O&M Variance from Base Case	468	664	698	671	656	

Capital Parameters	2014	2015	2016	2017	2018	Remarks
Base Case Capital Stream						
% Change in Customers	0.76%	0.89%	0.93%	0.94%	0.98%	Refer: Exhibit B-1,
Total Capital Under PBR	72,758	68,950	52,103	53,183	54,060	Table B6-7, Page 58
Scenario-1: Capital Stream using Forecast Load Growth Profile for Customer Growth						
% Load Growth Profile	1.44%	1.02%	0.99%	0.90%	1.09%	Refer: Exhibit: B-1-, Appdx-E2, Table-1.1, Page-1, Gross Load
Total Capital Stream	73,053	69,310	52,501	53,572	54,517	
Capital Variance from Base Case	295	360	398	389	457	
Scenario-2: Capital Stream using Polynomial Load Growth Profile for Customer Growth						
% Load Growth Profile	1.64%	1.22%	0.96%	0.86%	0.92%	Refer: Graph proded by BCUC IR-1 Q28.4
Total Capital Stream	73,140	69,491	52,673	53,730	54,596	
Capital Variance from Base Case	382	541	569	547	535	

As discussed in the Application Section 6, in the B&V PBR Report Appendix D-1 and the B&V TFP Report Appendix D-2 the Capital and O&M Streams during the PBR period are primarily a function of customer growth.

29.0 Reference: Exhibit B-1, p. 54

Unloaded Capital Expenditures

"In this Application FBC presents its capital expenditures before capitalized overheads, direct overheads, and AFUDC. From a project management perspective, 'unloaded' capital expenditures are those over which the Company has most direct control, and are therefore most appropriate to be determined by formula. The capitalized overheads, direct overheads, and AFUDC are included in Additions to Plant in Service (see Section E, Table 1-A-1)."

29.1 For any capital expenditures that could be delayed during the PBR term, how can the Commission determine the prudency of the costs incurred due to the delay?

Response:

As discussed in Exhibit B-1, the Company has proposed Annual Reviews, as well as a Mid-Term Review, of Company performance (including capital expenditures) as a means of maintaining transparency during the PBR term. These reviews will provide the necessary information for the Commission to determine whether reasonable grounds exist to question the prudence of decisions made by the Company with respect to capital expenditures incurred.

29.2 Please provide a multiplier to convert direct cost to total project cost that includes capitalized overheads, direct overheads, and Allowance for Funds Used During construction (AFUDC).

Response:

A multiplier to convert direct cost to total project cost that includes capitalized overheads, direct overheads, and AFUDC is provided in the table below.

Capital Expenditure Parameters		2014	Remarks
Unloaded Gross Capital Expenditure	**A**	**72,758**	Ref.: Exhibit-B1: Tab-E, Table 1-A-1, Pg 284, Line 72
Add Loadings:			
Capitalized Overheads		12,277	Ref.: Exhibit-B1: Tab-E, Table 1-A-1, Pg 284, Lines 68 to 70
Direct Overheads		5,000	
Estimated AFUDC		1,375	
Total Loadings:	**B**	**18,652**	
Total Loaded Gross Capital Expenditure	**C = A+B**	**91,410**	
Conversion Multiplier (For converting Unloaded Capital to Loaded Capital)	**C/A**	**1.26**	
Reconciliation to Exhibit B-1, Tab-E, Table 1-A-1, Pg 284:	**D**		
Less Cost of Removals (COR)		4,465	
Total Loaded Gross Capital Expenditure without COR	**E =C-D**	**86,945**	Ref.: Exhibit-B1: Tab-E, Table 1-A-1, Pg 284, Line 64

29.3 Please explain why direct overheads are considered unloaded for capital expenditures as they are direct costs.

Response:

The Company has presented its capital expenditures as those costs that the project manager has the most direct control over. For administrative ease, FBC allocates the Direct Overhead loading pool on a pro rata basis to each project based on the specific project expenditure as a ratio of the total T&D project expenditures. From this perspective Direct Overheads are allocated to the individual projects. A detailed discussion on Direct Overheads is found in Section 3.8 of the Application (pages 255- 257).

30.0 Reference: Exhibit B-1, pp. 51-54

O&M related to Implementation of the AMI Project

FBC states, "AMI-related expenses and reductions are excluded from the formula as the expenditure/savings profile is highly variable during the implementation period." (Exhibit B-1, p. 52)

30.1 Please explain why the O&M costs related to the implementation of the AMI project have been excluded from the O&M formula approach (tracked outside the formula).

Response:

Given that there are no O&M impacts in 2013 related to the AMI project, the 2013 O&M base amount applicable to the proposed PBR formula appropriately does not include any impacts related to AMI (as there are none). However, the O&M impacts (savings from 2015 onwards) are added back to the total O&M under PBR as shown in Table B6-5, thus ensuring that rates determined under the proposed PBR reflect the full benefit to customers attributable to the AMI Project.

30.1.1 Please discuss what is meant by "the expenditure/savings profile is highly variable" during the period 2014-2018 since the O&M expenditure/savings profile should commence in 2015.

Response:

It should be noted that the expenditure/savings profile related to the AMI project commences in 2014 as detailed in Table B6-5. The reference to "the expenditure/savings profile" as highly variable during the implementation period relates to the 2013 – 2015 timeframe which is the implementation period for the AMI Project.

Please see the table below which illustrates the variability of the forecast O&M impacts attributable to the AMI project for the 2014 – 2018 period:

($000s)	2014	2015	2016	2017	2018
Forecast AMI O&M Impact	368	(439)	(2,411)	(2,369)	(2,794)

Due to this variability, the impact of the AMI project is excluded from the determination of the 2013 base O&M applicable to the proposed PBR formula, which is appropriate considering there are no impacts to O&M related to AMI in 2013.

30.2 Please provide the gross and net O&M-costs related to the implementation of the AMI project for each year of the PBR term.

Response:

Please see the following table which details the gross O&M impacts related to the AMI project, as well as the net O&M impacts (Gross AMI O&M less Status Quo O&M):

AMI O&M Impact ($000s)	2014	2015	2016	2017	2018
Gross	4,868	4,132	2,407	2,434	2,493
Net	368	(439)	(2,411)	(2,369)	(2,794)

31.0 Reference: Exhibit B-1, pp. 54-55

Capital Expenditures under PBR

On page 55, FBC states that it "has included in its PBR formula the following three categories of regular capital expenditures – growth, sustainment, and other capital" (lines 29-30).

31.1 Does this mean that these three categories of capital are subject to the I-X mechanism? If not, please explain the treatment of each of these three categories of capital and explain why they are treated in that manner.

Response:

Confirmed, all three categories are subject to the I-X mechanism as discussed in the Application on pages 56 and 57:

"The following formula illustrates the formula applied to capital expenditures:

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

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

The inputs used for calculating capital expenditures under the PBR Plan include:

1. *The total 2013 Base Capital;*
2. *The 2013 base and forecast number of average customers, including its year to year percent change;*
3. *The composite I-Factor values; and*
4. *The Productivity X-Factor."*

32.0 Reference: Exhibit B-1, pp. 55-56

2013 Base Capital

FBC indicates that there are adjustments to 2013 capital for non-recurring major projects and adjustments for non-controllable items (page 56, lines 4-6).

32.1 Explain in detail how this will work. Do any of these adjustments relate to deferral accounts? If so, are the deferral accounts eliminated for the five years of the PBR plan? If they are not eliminated, what happens to the revenues in the deferral accounts and how are they handled on a year-to-year basis? Explain in detail. Relate this response to Table B6-7, PBR Capital Formula Inputs and 5-Year Forecasts, on page 58.

Response:

This question is the same as in FEI's 2014-2018 PBR Application, BCUC IR 1.18.1. This response is similar to the FEI response to that IR, however some differences are necessary in order to respond appropriately for FBC.

The deferral accounts are maintained for the five years of the PBR Plan, as the same rationale that justified deferral treatment in the past continues to apply during PBR. Please refer to the response to BCUC IR 1.22.2 in this regard. Regarding treatment and methodology, please refer to the response to BCUC IR 1.22.1 as the methodology for capital adjustments is the same as the methodology for O&M adjustments.

The adjustment to 2013 capital for major projects in Table B6-6 is necessary to determine a level of Base Capital to which the PBR formula will apply. These major projects must be deducted from the total capital program so that the Base Capital provides adequate funding, and no more, for the ongoing capital requirements over the PBR Period. In 2014 and future years, major projects will be tracked outside of the PBR formula as shown in Table B6-7.

The non-controllable items for the capital adjustments are limited to the PST and Pension/OPEB expense. The PST adjustment is a one-time adjustment to reflect the reintroduction of the PST in 2013 and once embedded in the base costs will not recur during the PBR Period (unless other changes to the tax structure occur, which are not expected). Pension expense will be reforecast annually for rate-setting purposes; the mechanism by which forecast pension costs will be reflected in capital expenditures is shown in Table B6-7. This forecast will be adjusted to actual annually by way of the Pension & OPEB Variance Deferral Account.

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32.2 If any deferral accounts were eliminated at the beginning of FBC's PBR plan, what changes, if any, would FBC recommend to its proposed PBR plan?

Response:

The deferral accounts referenced in point 2 at the top of page 56 of the Application are the PST and pension deferral accounts. The PST adjustment is one-time and therefore will be eliminated after the 2013 Base is reset (although the Tax Variance deferral account will continue). The pension deferral accounts are long standing deferrals that provide benefits to customers and the shareholder and FBC submits there is no basis on which to eliminate these accounts.

The pension deferrals are unrelated to the PBR plan introduction. The effect of eliminating these deferrals is the same regardless of whether FBC uses a formula-based PBR plan or a conventional cost of service approach. The purpose of these deferrals is the same - to avoid windfall gains or losses to either the shareholder or the customer and to smooth the rate impacts of large variances in pension expenses into customers' rates.

33.0 Reference: Exhibit B-1, pp. 56-57

Capital Expenditures

33.1 Does the PBR process reduce the risk of cost recovery for capital expenditures subject to the PBR formula? Please discuss.

Response:

In general, PBR increases risk because of the longer period until cost rebasing occurs. With respect to capital expenditures specifically, FBC believes that the risk of cost recovery for capital expenditures is not changed under PBR as long as the X-Factor reasonably represents the average productivity of the industry because:

(a) in both cost of service and PBR, rates are fixed prospectively and the corporation manages capital (which determines return, taxes and depreciation expense associated with capital expenditures) to the approved amount, so the risk is one of exceeding the approved amount rather than disallowance; and

(b) after the test/PBR period, recovery associated with that capital incurred during the specific test/PBR period is subject to the same test of prudence.

33.1.1 If so, please explain why FBC did not propose a lower return on capital expenditures subject to the PBR formula? If not, please explain why not.

Response:

A utility's allowed return is determined with reference to the risk profile of the Company as a whole, and the allowed return does not differ by asset class. PBR does not reduce FBC's overall risk, and thus should not result in a lower return. This is particularly true when the proposed X-Factor is substantially above the expected TFP value and therefore represents a substantial performance risk to balance service quality, operating costs and capital costs under the proposed Plan. B&V adds that, from a risk perspective, this would be defined as an asymmetric risk (the probability of performing at or above this level is less than the probability of performing below the level). Asymmetric risks increase the cost of equity all else equal because the estimate of equity costs assumes that risks are symmetric.

33.2 What is the discount rate used in the AMI Application?

Response:

The costs and benefits in the AMI Application were calculated using an 8 percent discount rate.

33.3 What is the inflation rate used in the AMI Application?

Response:

An inflation rate of 1.8 percent per year was used for all aspects of the AMI project not covered by fixed unit pricing or fixed price contract.

33.4 What is the discount rate applied to regular capital expenditures subject to the PBR formula? Please discuss.

Response:

The current discount rate is 8 percent (nominal). The Company would only apply the discount rate to regular capital expenditures if it needed to compare the net present value (NPV) of revenue requirements of various capital alternatives in order to determine which alternative would have the lowest impact on customer rates.

34.0 Reference: Exhibit B-1, pp. 57, 179, 258, Table D4-1

Major Capital, Capital and O&M Expenditures

Non-Recurring and Major Expenditures

34.1 Please provide a definition for major capital, non-recurring capital, and non-recurring O&M expenditures and include the estimated amounts and estimated frequency of expenditure if the expenditure repeats outside of the PBR term.

Response:

The definitions of major capital and non-recurring capital are not exclusive. Both Regular Capital and Major Capital projects may be non-recurring in nature.

For the purposes of the PBR Plan, it is the distinction between Regular Capital and Major Capital that is important: Major Capital projects are excluded from the formula-driven portion of capital expenditures (see Table B6-7):

- PCB Compliance – Substations; and
- Advanced Metering Infrastructure Project.

The projects for which FBC intends to file CPCN applications identified in Section C5.7 are also major and non-recurring projects.

While some O&M Expense may be non-recurring in nature, during the PBR Period FBC has not forecast any non-recurring O&M items that require consideration outside of the PBR formula. The Company does not expect that it will bring forward any such items, other than uncontrollable and unforeseen events which would qualify as Exogenous or Z-Factors, as described in Section B6.3.3

34.2 Please explain why FBC is seeking deferral account treatment for "non-recurring matters."

Response:

FBC is judicious in its use of deferral accounts and is not seeking deferral account treatment for all non-recurring matters. The reference to non-recurring matters is intended only to say that items which are appropriately accorded deferral account treatment are often non-recurring in nature. The explanations for why deferral account treatment is sought for specific items is set out in Exhibit B-1, Tab D(4).

34.2.1 Please provide a listing of all "non-recurring matters" including an estimated amount by item that FBC is seeking deferral account treatment for.

Response:

The highlighted items in the following table, derived from Table 1-B (2014) at page 287 of the Application, are those which FBC considers to be 'non-recurring' in nature, during the proposed PBR term. Items which recur periodically, such as the Company's long-term capital plans or periodic cost of service analyses, for example, are not considered to be non-recurring for the purpose of this response. Note that other than the Generic Cost of Capital Revenue Requirements Impact (Line 8) and the BC Hydro Application for Power Purchase Agreement with FBC (Line 27), the highlighted accounts have been previously approved.

Line	Account	Mid-Year Balance 2014 ($000s)
1	**Energy Policy**	18,615
2	Demand Side Management	**18,615**
3		
4	**Revenue and Power Supply Variance**	
5	Rate Stabilization Deferral Mechanism (RSDM)	(11,284)
6	Power Purchase Expense Variance Deferral	(7,479)
7	Revenue Variance	3,900
8	Generic Cost of Capital Revenue Requirements Impact	(1,827)
9		**(16,690)**
10	**Non-Controllable Items**	
11	Pension & Other Post-Employment Benefits (OPEB) Expense Variance	6,833
12	Prepaid Pension Costs and OPEB Liability	(16,941)
13	US GAAP Pension and OPEB Transitional Obligation	4,501
14	Insurance Expense Variance	-
15	Interest Expense Variance	-
16	Tax Variance	-
17	Property Tax Variance	-
18		**(5,607)**

Line	Account	Mid-Year Balance 2014 ($000s)
19	**Preliminary and Investigative Charges**	
20	Preliminary and Investigative Charges	150
21	Corra Linn Spillway Concrete & Spill Gate Rehab CPCN	41
22	Kelowna Bulk Transformer Capacity Addition (KBTCA)	171
23		**362**
24	**Regulatory Compliance**	
25	2014-2018 Performance Based Ratemaking (PBR) Application	343
26	2014-2018 Annual Reviews	38
27	BC Hydro Application for Power Purchase Agreement with FBC	65
28	BCUC Generic Cost of Capital Proceeding	242
29	BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program	39
30	Kettle Valley Expenditure Review	74
31	Transmission Customer Rate Design	75
32	City of Kelowna Acquisition Legal and Regulatory Costs	187
33		**1,063**
34	**Other**	
35	Earnings Sharing Mechanism (ESM) Deferral	-
36	Right of Way Reclamation (Pine Beetle Kill)	779
37	2012 Integrated System Plan - Engineering	842
38	2014-2018 Capital Expenditure Plan	438
39	2012 MRS Audit	235
40	MRS 2012-2013 Incremental O&M Expense	476
41	City of Kelowna Acquisition Customer Benefit	(1,321)
42	Deferred Debt Issue Costs	4,789
43		**6,237**
44	**Residual**	
45	2011 Flow-Through and ROE Sharing Mechanism Adjustments	(523)
46	2012 Deferred Revenue	5
47	Harmonized Sales Tax (HST) Removal/Provincial Sales Tax (PST) Implementation Project	154
48	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	148
49	Cost of Service and Rate Design Application	212
50	2012-2013 Revenue Requirements and 2012 Integrated System Plan	(368)
51	2011 Revenue Requirement Application costs	1
52	Residential Inclining Block Rate	61
53	Implementation of New Rate Structures	(1)
54	Irrigation Rate Payer Group Consultation and Load Research	(8)
55	Negotiation of new PPA between BC Hydro and FBC	93
56	Right of Way Encroachment Litigation	47

Line	Account	Mid-Year Balance 2014 ($000s)
57	Princeton Light and Power Deferred Pension Credit	(6)
58	US Generally Accepted Accounting Principles Conversion Costs	(60)
59	Joint Pole Use Audit, 2013	(10)
60	MRS Implementation	152
61	Revenue Protection	(6)
62		**(109)**
63		
64	**Total**	**3,872**
65		
66	Subtotal, "Non-Recurring"	**4,322**

34.2.2 Identify the non-recurring types of capital on p. 179 of the Application and provide justification that it is non-recurring.

Response:

Of the projects listed on p. 179 (and as noted on p. 57), the following projects are considered non-recurring:

1. The substation portion of the PCB Environmental Compliance program, which will be completed during 2014, described in Section C5.4.3.1 of Exhibit B-1; and
2. The Advanced Metering Infrastructure project and the associated Information Systems expenditures, described in Section C5.6.9 of Exhibit B-1.

With respect to the PCB Environment Compliance, the activities associated with the project are driven by external regulation are non-recurring by the nature of the project (removal and/or containment of PCB contaminated equipment).

AMI is a discrete capital project to replace the existing non-AMI meters with AMI meters. Although there are recurring sustaining capital expenditures associated with this project, the implementation costs of the project are by definition non-recurring.

34.3 For the remaining major capital expenditures, please explain and discuss why they are not included in the base.

Response:

As shown in Table C5-2 of the Exhibit B-1 the following 2013 Major Projects were not included in the determination of the 2013 Base Capital:

- PCB Environmental Compliance
- Kelowna Bulk Transformer Capacity Addition
- Trail Office Lease Purchase
- Kootenay Long Term Facility
- Okanagan Long Term Solution Project
- Advanced Metering Infrastructure

These projects are not recurring expenditures and are not representative of the types of on-going requirements that the proposed PBR mechanism is intended to apply to. As such, they are appropriately excluded from the determination of the 2013 Base Capital.

34.4 Provide a summary listing of the Major Capital and "non-recurring" Expenditures for the years 2007-2012 and a forecast of the years 2013-2018, including the total capital and O&M expenditures using the table provided below.

	Summary of Expenditures by Year				
Year	Major Capital	Capital Non-Recurring	O&M Non-Recurring	Total of All Capital	Total of All O&M
2007					
2008					
2009					
2010					
2011					

2012					
2013					
2014					
2015					
2016					
2017					
2018					

Response:

FBC explains in its response to BCUC IR 1.34.1 that both Regular Capital and Major Projects can have non-recurring projects. The table below provides the expenditures for the two categories. Significant and non-recurring O&M Expense that meets the definition of Exogenous Factor (see Section B6.3.3 would be outside of the O&M Formula but FBC does not have knowledge of any such factors over the term of the PBR Plan.

<table>
<tr><th rowspan="2">Year</th><th colspan="5">Summary of Expenditures by Year</th></tr>
<tr><th>Major Capital</th><th>Regular Capital</th><th>Total Capital</th><th>O&M Non-Recurring</th><th>Total O&M</th></tr>
<tr><td>2007</td><td>58,898</td><td>70,291</td><td>129,189</td><td colspan="2" rowspan="12">All of O&M is considered recurring</td></tr>
<tr><td>2008</td><td>42,396</td><td>57,191</td><td>99,587</td></tr>
<tr><td>2009</td><td>45,774</td><td>53,395</td><td>99,169</td></tr>
<tr><td>2010</td><td>75,455</td><td>55,035</td><td>130,491</td></tr>
<tr><td>2011</td><td>27,757</td><td>48,452</td><td>76,209</td></tr>
<tr><td>2012</td><td>10,301</td><td>42,091</td><td>52,392</td></tr>
<tr><td>2013</td><td>67,584</td><td>65,609</td><td>133,193</td></tr>
<tr><td>2014</td><td>8,762</td><td>63,996</td><td>72,758</td></tr>
<tr><td>2015</td><td>-</td><td>68,950</td><td>68,950</td></tr>
<tr><td>2016</td><td>-</td><td>52,103</td><td>52,103</td></tr>
<tr><td>2017</td><td>-</td><td>53,183</td><td>53,183</td></tr>
<tr><td>2018</td><td>-</td><td>54,060</td><td>54,060</td></tr>
</table>

35.0 Reference: Exhibit B-1, p. 61

Prudent Expenditures

The Application states "Similarly, it is important to allow full recovery of these costs under a PBR plan, as the costs - being outside the control of management - are by definition prudently incurred costs of providing utility service that should be recovered from customers in the normal course."

35.1 Please discuss how FBC will be able to demonstrate prudency of its other management-controllable expenditures under the proposed PBR regime.

Response:

FBC's actual expenditures in the management-controllable categories (i.e. the formula-based O&M and capital) will be carried out under the terms and provisions of a Commission-approved PBR model for ratemaking purposes. In approving the PBR the Commission will have exercised its discretion under section 60 (1) (b.1) of the UCA to "use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period …". FBC management-controllable expenditures associated with the PBR term will be recoverable during the PBR term by virtue of FBC having complied with the approved provisions of the PBR Plan. Capital expenditures incurred during the PBR period must still be prudent if the revenue requirement impact associated with those expenditures is to be recoverable in the years following the conclusion of the PBR.

36.0 Reference: Exhibit B-1, p. 63

2013 Adjustments – BC Mandatory Reliability Standards (MRS)

FBC states "In the nomenclature of PBR, non-controllable and unforeseeable costs that flow through to rates are referred to as exogenous factors or Z-Factors."

36.1 Does FBC consider MRS to be a Z-Factor item? Why or why not?

<u>Response:</u>

No, since MRS is already part of the embedded O&M. However if in the future there were cost increases arising from MRS requirements, that would be considered a Z-Factor because those cost increases are not controllable and are not in base O&M.

37.0 Reference: Exhibit B-1, pp. 61-63

Flow-Through Expenses

37.1 FBC proposes to flow through a forecast of interest expenses. Will these forecasts of interest expenses be trued up? If not, explain the incentives and consequences in detail.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.21.1. This response is identical to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Interest expense is "trued up" in the sense that customers pay for actual interest rates incurred. This is achieved through amortization of the Interest Variance deferral account in subsequent years' rates. This deferral account covers both long term debt interest variances and short term interest rate variances. Long term debt interest, which comprises more than 97% of the interest expense, is adjusted to actual amounts based on debt issue timing variances, principal amount variances and interest rate variances. Short term debt, which accounts for less than 3% of the interest expense, is adjusted based on variances between the actual short term debt rate and the forecast short term debt rate. This is the same treatment accorded to FEI's interest expense.

37.2 Explain why changes in interest expenses are not captured in the I-Factor.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.21.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Consistent with the 2007 PBR Plan, the PBR formula applies only to the controllable O&M and capital components of costs. Interest expense is largely outside of FBC's control and interest rates have historically been subject to flow through or deferral account treatment. Capturing items in a deferral account results in actual costs being recovered from customers; applying a PBR formula results in formula-driven amounts being recovered from customers.

Since the bulk of interest expense is driven by interest expense on embedded debt, only a small amount is subject to forecasting in any given year. It is unlikely that the interest expense escalation that is forecast would be expected to follow a trend of general inflation, with or without an X factor offset.

Changes in interest expense are not captured in the I-Factor because the impact of interest expense on the rate of inflation is only the current rate effect. Actual interest expense for a utility reflects higher leverage than for the economy as a whole and a larger portion of sunk costs than for the economy. In addition, interest expense is a function of the level of capital spending from period to period that is not likely to match the implied capital spending in an index of general inflation.

37.3 Explain why changes in Commission-approved Return on Equity (ROE) are not captured in the I-Factor.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.21.3. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Please refer to the response to BCUC IR 1.37.2. ROE changes with the market and the capital structure of the utility. Since there is to be a regular re-determination of ROE for the utility within the proposed PBR period, these changes out of necessity must be passed through separately. Finally, the TFP calculation does not reflect the utility's allowed ROE, but rather the actual earned ROE that may or may not equal the actual allowed ROE. The reflection of actual earned ROE would also create a lag in the adjustment for the cost of equity.

37.4 Will forecasted revenues (page 62, lines 22-29) be trued up? If not, explain the incentives and consequences in detail.

Response:

Variances in sales revenue from forecast will be captured in the Revenue Variance Deferral Account and flowed through to rates in the following year.

The referenced statement contains an error. Section B6.3.2, from which the preamble to this question is taken, identifies the Company's existing and proposed flow-through accounts. The reference to sources of revenue in Section C3 is to Other Income, which is not a flow-through item. The Revenue Variance flow-through is applicable only to revenue from sales. The statement, which is corrected in Errata #2, should read: “Flow-through revenues are amounts received from customers for the sale of electricity.”

37.5 Will the smaller components of rates, as described on page 63, lines 13-17, be trued up? How does this related to the Annual Review process? If these costs are not trued up, explain the incentives and consequences in detail.

Response:

This question is identical to FEI’s 2014-2018 PBR Application, BCUC IR 1.21.5. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

The smaller components of rate base described on page 63, lines 13 -17 of the Application will be reforecast each year based on up-to-date information known at the time of the Annual Review. Actual results for these items may vary from forecast and give rise to positive or negative earnings variances in the year. These variances will be subject to the 50/50 ESM. The variances in any particular line item will not be expected to recur in the following year because the reforecasting of that line item at that time will use the most up-to-date information. Under conventional cost-of-service-based RRAs, 100 percent of the earnings variances attributable to these other rate base components would affect FBC’s rate of return during the test period while, under the PBR, 50 percent will be attributed to customers through the ESM. Earnings variances from these other rate base items will not be included in the Efficiency Carryover Mechanism.

38.0 Reference: Exhibit B-1, p. 63

Exogenous Factors

38.1 Is there a materiality threshold for exogenous factors? If not, why not? If yes, what is the materiality threshold and how was it determined? Provide the justification for the threshold.

Response:

No. Placing a materiality limit is most likely to deny prudent cost recovery and thus increase the underlying risk. The cost increases or decreases arising from exogenous factors are non-controllable costs that would be subject to recovery in rates under cost of service-based ratemaking without any materiality threshold. The appropriate mitigation of this risk is to not set a limit on recovery.

39.0 Reference: Exhibit B-1, p. 64

Earning Sharing Mechanism (ESM)

39.1 Explain the effect on incentives from including an ESM in FBC's PBR plan.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.23.1. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Including the proposed 50/50 ESM in the PBR Plan shares the benefits from efficiencies achieved equally between customers and the Company. Customers therefore receive 50% of the benefits during the PBR (and efficiency carry-over period) and then receive 100% of the benefits after that.

Based on the success of FBC's prior PBR Plan which included the same ESM (along with similar other PBR Plan elements), FBC believes that inclusion of the same 50/50 ESM in the 2014 PBR Plan is appropriate and will provide FBC with suitable motivation to pursue efficiencies as it did in the previous PBR Plans. As well, while the proposed PBR Plan is structured such that the initial 0.5% of productivity achieved accrue to the customers, to the extent the Company is able to exceed that level, customers will further benefit.

39.2 If there were no ESM in the PBR plan, would FBC suggest an increase in the X-Factor? If so, why, and how much?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.23.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

If there was no ROE sharing through an ESM, it would be necessary to consider changes to more than the level of the X-Factor, including off-ramps and reopeners. The absence of an ESM changes the risk profile for FBC because there is no longer a sharing of the shortfalls or gains. With the positive X-Factor that is well above the negative TFP value, over the term of the PBR, it is uncertain as to the likelihood of achieving or surpassing the productivity target. The ESM, while ensuring customers benefit from positive performance, somewhat mitigates the Company's downside risk associated with the aggressive positive X-Factor.

As noted in the evidence at page 47, with earnings sharing the X-Factor is less significant than with no earnings sharing. In all likelihood this could mean, absent an ESM, using an X-Factor that directionally is closer to the actual TFP value, which would likely result in a negative value for the X-Factor. FBC has not analyzed its risk profile under this option since it is inconsistent with the overall context of its proposed PBR Plan. As a result, it is not possible to quantify precisely the magnitude of a change to the X-Factor.

39.3 What is the relationship between and ESM and provisions to re-open the PBR plan during its five-year term? Explain in detail. If there were no ESM, would FBC propose any changes to the re-opener provisions? If so, explain why and what these changes would be.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.23.3. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

ESM, off-ramps and re-opener provisions are safeguard mechanisms that protect the utility and customers from potential unexpected negative consequences of the PBR plans. Similar to the 2004 FEI PBR Plan, FBC's proposed ESM is linked to the off-ramp provision through the off-ramp financial trigger mechanism and the proposed 200 basis point trigger over or under the allowed ROE is calculated after earnings sharing.

It is clear that without an ESM, the role of other safeguard mechanisms becomes more important and that the proposed off-ramp financial trigger should be changed to accommodate for the PBR Plan's changed risk/reward balance. It is not possible to comment on the magnitude of this change without knowing the changes in all of the other PBR elements that may affect the overall risk/reward balance of the plan, since any PBR plan is composed of complementary elements.

40.0 Reference: Exhibit B-1, pp. 64-65

Proposal for ESM

40.1 Why did FBC select the proposed structure of the ESM? Did FBC consider a deadband, so if the ROE fell within this band around the approved ROE, there would be no earnings sharing? If there were a deadband in the ESM, what would FBC consider to be a reasonable deadband, and why?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.24.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

FBC reviewed the merits of various ESM structures and also considered its own experience with ESM to decide on the best option. FBC decided not to use a dead-band for following reasons:

1. **Success of 2007-2011 PBR ESM**: The 2007 ESM structure did not have any dead-band. Ratepayers benefited from this framework since all of the PBR related gains were shared with them. In the 2007 PBR Plan the inclusion of a dead-band would have decreased the ratepayers' share of PBR benefits.

2. **Regulatory burden associated with using a dead-band:** A review of ESM structures with dead-band in other Canadian jurisdictions indicates that the inclusion of a dead-band has the potential of increasing the regulatory burden. For instance the OEB's consultant reviewed the ESM structure of Enbridge and Union during their 2008-2012 PBR Plans and concluded that "computing the returns to be shared in an ESM is an inherently controversial issue, and this process sometimes leads to mini rate cases that involve significant regulatory costs and delays." FBC believes that the controversy surrounding the OEB's approved ESM is influenced by the use of dead-bands.

3. **The no dead-band ESM better conforms with FBC's PBR principles:** With regard to PBR principles a no dead-band ESM scores better than other ESM design options as it aligns the interests of customers and the Utility to the greatest extent possible and it is easier to understand, implement and administer and may reduce the regulatory burden over time.

Consequently FBC is not proposing any dead-band. FBC believes that in the context of its overall PBR proposal the proposed ESM, in combination with the efficiency carry-over mechanism will provide suitable motivation to pursue efficiencies for the longer term benefit of ratepayers.

40.2 Is FBC's ESM symmetrical? In other words, will customer prices be increased if the ROE is below the approved ROE?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.24.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Yes, similar to FBC's 2007-2011 PBR plan, FBC's proposed ESM is symmetrical. If the achieved ROE in any year is below the allowed ROE the resulting rate adjustment will increase customer rates for the subsequent year to recover FBC's 50% share of the ROE shortfall.

40.3 Did FBC consider any other structure for its ESM other than the 50/50 sharing it proposed? For example, did FBC consider either an increasing or decreasing share of earnings to customers above or below the approved ROE? Why or why not? As an example, did FBC consider an ESM in which earnings above the approved ROE be shared with 70 percent to customers, then 50/50, and then, perhaps, 30 percent to customers and 70 percent to the company as earning rose above the approved ROE? Discuss the incentive properties of alternative ESM structures.

Response:

This question is identical to BCUC IR 1.24.3 in FEI's 2014-2018 PBR Application. That response directed the reader to two other FEI responses: BCUC IR 1.24.1 and CEC IR 1.48.3. The response below is taken from the FEI response to CEC IR 1.48.3, however minor changes were necessary in order to respond appropriately for FBC.

In addition to the symmetrical 50/50 earnings sharing approach proposed by FBC, various other approaches have been proposed and adopted for ESM elsewhere such as no earnings sharing, asymmetric earnings sharing, earnings sharing outside of a dead-band, increasing percentages of earnings sharing at prescribed ROE levels relative to a benchmark and decreasing percentages of earnings sharing at prescribed ROE levels relative to a benchmark, to name some. The last alternative mentioned is similar to the one mentioned in the question. In that approach to an ESM, smaller percentages of the gains are shared with customers at higher ROEs above the threshold.

While there may be merits to the various alternative ESM approaches, in these particular circumstances FBC believes its proposed approach is appropriate as an element of the 2014 PBR Plan. The 50/50 symmetrical earnings sharing model has been successfully employed in FBC's previous PBR plan. FBC's ESM provides a consistent business case metric for pursuing additional efficiencies at all levels of ROE achievement (short of reaching the off-ramp). FBC's ESM will generate less controversy and regulatory process around the calculation of earnings sharing than with dead bands or where sharing percentages change at certain ROE levels.

Please also refer to the response to BCUC IR 1.40.1.

41.0 Reference: Exhibit B-1, pp. 65-68

Enhancing the Effectiveness of the FEI 2004-2009 ECM

41.1 Provide a numerical example to illustrate how the proposed efficiency carry-over mechanism (ECM) would work with O&M and capital savings made at various years during the term of the PBR plan. This should clearly show how the savings were calculated and the effect on customer prices during subsequent years. The example should also show the role of forecasts in determining savings (see, for example, page 67, lines 26-28), the incentives created by the use of forecasts, if any, and whether or not such forecasts are trued up.

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.25.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

An illustrative numerical example of how the ECM would work is provided in Appendix D5, page 3, Exhibit B-1-1. A written description of the components of the numerical example is provided in Appendix D5, pages 1 and 2. The example in the Appendix shows that the calculation will be based on the difference between the formula-based amounts as calculated in that year, and the actual amounts. Since the calculation of the ECM is a backward looking calculation, the formula-based amounts to be included in the calculation will be based on the actual cost drivers (i.e. actual average customers and actual service line additions experienced in each of the years).

42.0 Reference: Exhibit B-1, pp. 69-71

Mid-Term Review and Off Ramps

42.1 Discuss the relationship between the mid-term review and off ramps and the value of the X-Factor and the ESM. Specifically, would the absence of a mid-term review affect FBC's recommendation for the X-Factor or the terms of its proposed ESM? Would changes in the off ramps affect FBC's recommendations for the X-Factor or the terms of its proposed ESM? Conversely, would changes in the X-Factor or the ESM change FBC's recommendations regarding the mid-term review or off ramps?

<u>Response:</u>

This question is similar to FEI's 2014-2018 PBR Application, BCUC IR 1.26.1. This response is similar to the FEI response to that IR, but some minor changes were required to respond appropriately for FBC.

B&V concludes that any change in FBC's PBR Plan would impact other elements of its Plan. Since the X-Factor is a major element of the Plan, changes in any of the other design elements of the Plan would require a reassessment of the X-Factor.

With respect to the two items mentioned in the question, changes in the off-ramps, other plan provisions remaining the same, would likely be a more significant concern of the two. With off-ramps, stakeholders are protected from outcomes that would otherwise not meet the standard that a utility be allowed a reasonable opportunity to recover its prudently incurred costs and earn the allowed return. Eliminating the off-ramp or making it asymmetric by setting only an upper limit on the earned ROE without a floor would effectively make it necessary to have the X-Factor move in the direction of the industry average of minus four percent in order to meet the test of providing a reasonable opportunity to earn the allowed return.

Regarding the Mid-Term Review, this concept was a component of FEI's 2004 PBR Plan that was introduced to address the concerns of some parties about having a longer term PBR and where undesirable and unanticipated outcomes not covered by other plan provisions could be given consideration without having to abandon the overall plan. Although the Mid-Term Review in FEI's 2004 PBR Plan was mainly a confirmation that the plan was working well and did not lead to any changes in the Plan FBC believes it is appropriate to include the Mid-Term Review in the 2014 PBR Plan as a risk mitigation element for both FBC and customers.

43.0 Reference: Exhibit B-1, pp. 71-72

Annual Review

43.1 Regarding point 18 at the top of page 72, are there any forecasts that are used to determine projected earnings and trued up actual earnings? If so, are these forecasts trued up and are the actual earnings adjusted to take into account any difference between the forecasts and the actuals? If not, what are the incentives created by not truing up these forecasts and the consequences? Why has FBC chosen not to true up these forecasts?

<u>Response:</u>

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.27.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Customers will receive (or be charged) the full correct amount, based on actual results, of the 50/50 earnings sharing through the ESM rate rider. It will be necessary to make a projection of earnings sharing at the Annual Review because the year for which the sharing is being calculated will not be complete until after the Annual Review has occurred. However, FBC will recalculate the earnings, and earnings sharing, based on actual results after the year is complete when its Annual Report is provided to the Commission. Any variances, positive or negative, between projected and actual earnings sharing will be adjusted through the ESM rate rider during the next Annual Review. This is the same approach that was agreed to during the 2007 to 2011 PBR period.

44.0 Reference: Exhibit B-1, p. 2

TableA1-1: Summary of 2014 PBR Plan Proposal

44.1 The section of the table on "Controllable Expenses – O&M" states "O&M will not be rebased during the PBR term but will be reforecast annually." Explain in detail exactly what this means. What is the difference between reforecasting annually and not being rebased? How will this work in practice?

<u>Response:</u>

The entire cell in Table A1-1 that is referenced in the question reads as follows:

> A formula based approach for O&M is proposed. 2013 approved O&M expenditures (with adjustments) are adopted as the base O&M. The O&M formula will adjust the prior year's formula O&M by forecast customer growth and (I-X). O&M will not be rebased during the PBR term but will be reforecast annually.

The annual reforecasting referred to in Table A1-1 is a recalculation each year of the formula-based O&M allowance using a reforecast of the average number of customers and a reforecast of the composite inflation rate (see page 57 of the Application). These average customer and I-Factor reforecasts will be done each fall at the Annual Review for the coming year and will use the most up-to-date information at the time.

By contrast, rebasing of O&M would constitute adjusting the base O&M to actual levels. If O&M was, in some sense, rebased during the PBR term this would effectively remove all or most of the incentive power of the PBR Plan and defeat the purpose of pursuing PBR to begin with.

45.0 Reference: Exhibit B-1-1, Appendix D1, p. 32

Alberta Utilities Commission (AUC) Plan

"This assumption [that throughput explains the cost structure of the utility] has been demonstrated to be false time and again by cost of service analysis."

45.1 Provide support for the statement that this assumption, that throughput explains the cost structure of the utility, has been demonstrated to be false time and again.

Response:

B&V provides the following response.

In cost of service analysis for electric utilities the costs for transmission and distribution are allocated on demand or customer. There is no basis for allocation on throughput otherwise regulators would weather normalize distribution and transmission costs in a rate case. The design and operation of an electric utility system relies on the expected design hour load to install system components that, in general, meet the load with a margin for reserve to protect the system component. Volume or kWh used does not impact the costs for distribution or transmission. There is no basis in the design and operation of the delivery portion of an electric system to even consider the kWh as an output of the cost inputs. See for example the NARUC Electric Utility Cost Allocation Manual that discusses the classification of distribution plant on either customer or demand. Further, transmission costs are incurred based on the maximum load to be carried on the facilities- a demand consideration only. Finally, if system costs were a function of kWhs regulators would weather normalize the costs as part of a rate case. They do not because the costs do not vary with kWhs. Also refer to Attachment 45.1 for an excerpt of the discussion pages from Electric Utility Rate Economics by Russell Caywood.[13]

FBC adds that the difference between energy and customer and capacity driven costs is reflected in the functionalization and classification steps in Fully Allocated Cost of Service (FACOS) studies used in this jurisdiction. For example, the Commission described the FACOS process as follows in its Order G-36-07 and Decision in the 2007 BC Hydro rate Design Application (p.83-84):

> *In cost of service studies the distribution system is commonly split between the portion of the system which was constructed solely as a result of the customer requiring service, of which customer metering is the most common example, and the portion of the system constructed because of the demand placed on electrical equipment. Distribution substations are generally classified 100 percent demand, and all equipment between this point and the meter may be determined to be demand or customer-related.*

[13] Electric Utility Rate Economics by Russell Caywood, Published by McGraw Hill 1972

The methods used to determine the demand/customer split are more fully described by EES:

> *"There are three basic methodologies to classify distribution costs: basic customer charge (sometimes called 100% demand), minimum system and zero intercept. Variations around these three basic methods are also common. The basic customer charge methodology assumes that the distribution system is built to meet the customers' non-coincident peak demand. Therefore, the basic customer charge methodology classifies customer accounting, and O&M and capital costs for meters and services as customer-related, while the remaining distribution costs are classified as 100% non-coincident demand-related. Distribution costs are also sometimes split between demand and customer according to a zero intercept or minimum system methodology. These methodologies reflect the philosophy that the distribution system is in place in part because there are customers to serve throughout the service territory expanse, and that a zero or minimally-sized distribution system is needed to serve these customers even if they only have a 100 watt light bulb in their residences. The concept follows that any costs associated with a system larger than this minimal size are due to the fact that customers "demand" a delivery quantity of electricity greater than the minimum. These costs required to meet demands greater than those met by the minimum system are treated as demand-related (Exhibit C7-4, Testimony of EES Consulting, pp.16, 17)."*

B&V concludes that if kWh does not cause costs to be incurred by an electric utility, it cannot be a valid measure of TFP because productivity is measured in terms of what is actually produced. Electric kWh is not the product of an electric delivery system. Output consists of customer connections and various measures of peak load capacity.

45.1.1 If the assumption is false for a cost of service analysis, explain, with references to the economics literature on TFP growth studies, why this assumption is false for TFP growth studies.

Response:

B&V concludes that if throughput does not cause costs to be incurred by an electric utility, it cannot be a valid measure of TFP because productivity is measured in terms of what is actually produced. KWH or MWH is not the product of the electric delivery system. Output consists of customer connections and delivery capacity in the various components of the system based on reduced load diversity as load is measured nearer to the customer premise.

The economics literature has only sparse references to measures of output because both in theory and practice for most studies output is measured in conventional quantity measures such as “widgets.” Further, most academic economists simply define the outputs of a delivery service that is not a part of the overall production process where volume is a cost driver. Since the delivery of electricity is separate and apart from the production and since the only quantity of delivery that matters is the peak hour demand delivery at various measurement points on the system, this is a different basic model of service than for any other delivery business. Consider UPS that delivers thousands of parcels per day. They have no fixed facilities dedicated to a customer, there are no constraints on the timing of the deliveries, delivery trucks can be rented for peak periods, and so forth. If package sorting equipment is overloaded, packages may be delayed but there is no permanent loss of service to all customers in a specific area as would be the case if the electric system becomes overloaded and circuits trip. Further, the only economic consequence is for those customers whose packages are not delivered not for all customers in the area. All things considered, most economists have not studied the depth and complexity of these issues for utility delivery service and, as a result, they use commonly available data that fits the academic paradigm.

Please also refer to the response to BCUC IR 1.45.1.

45.2 Please comment on the AUC’s statement in paragraphs 394 and 395 of AUC Decision 2012-237, supported by the experts testifying in that proceeding, that the selection of an output measure for a TFP growth study depends on the nature of the PBR plan, whether it is a revenue cap or a price cap.

Response:

B&V provides the following response.

Please refer to paragraph 396 of that decision that notes that there is no consensus on the best measure of output for TFP studies as filed before the AUC. As discussed in both B&V’s Productivity Report in Appendix D-2 and the report on recent regulatory decisions in Appendix D-1, there is a superior measure of output for an electric utility, namely, customers and capacity. There is ample discussion of the deficiencies of using kWhs to measure output supported by both theory and practice, as well as by real world examples. If a properly measured output is used, there is no need to distinguish between a revenue or price cap structure. The experts in the AUC proceeding all followed the academic paradigm with its fatal internal inconsistency that throughput is caused by, and directly related to, the various inputs. Some of the experts correctly recognized that customers play a role in the measure of output, but did not make the necessary analytical modifications to utilize the output measure of capacity.

Subsequently PEG, which had testified before the AUC, has modified its estimation of TFP for electric distributors in Ontario to include customers, capacity and throughput. Under this modification, PEG weights each component with throughput having the smallest weight. Eliminating throughput from the output measure would have minimal impact because of its low weight and would allow the output specification to match cost causation. PEG, however, did not use an appropriate measure of capacity for the distribution utilities in Ontario because they used the system coincident peak load. While this is a movement toward a correct measure, the use of the sum of class NCPs would have been more appropriate and a measure of installed capacity such as the one used by B&V would have been most appropriate. To that extent, there is a movement toward a more correct and theoretically correct output specification.

The fundamental issue with the academic studies is that they use the academic paradigm as applied to conventional industrial output such as manufacturing widgets. For both gas and electric utilities, the output is not the volume of widgets but the capacity to deliver widgets on highly varying demand to customers dispersed over an integrated network. Thus, the inputs produce not volumes of gas or electricity but peak hour delivery capacity for providing system reliability and customer attachments to the network. It is not reasonable to measure output that is not produced, although from an academic point of view, it is much easier to obtain the data for throughput as opposed to making the necessary estimate of capacity.

45.3 What would B&V propose as an output measure in a TFP study if the PBR plan involved a price cap? Explain and justify the output measure.

Response:

TFP is correctly measured with reference to customers and capacity when either a price cap or revenue cap is being used because the type of cap used does not change the outputs of the utility. Please refer to the response to BCUC IR 1.45.2.

46.0 Reference: Exhibit B-1-1, Appendix D2, p. 2; Appendix D1, p. 31

Total Factor Productivity (TFP)

Beginning on page 2 of Appendix D2, the B&V Report describes the theoretical basis for measuring productivity in a TFP study.

On page 31 of Appendix D1, B&V state that "(t)he AUC approach to X-Factor relied too heavily on an academic approach that did not reflect either the cost drivers or the proper measure of outputs for electric and gas utilities." (Exhibit B-1-1, Appendix D1, p. 31)

46.1 Explain in detail how the theoretical basis in the B&V Report differs from the theoretical basis of the NERA Economic Consulting (NERA) report on which the AUC relied on for its PBR decision.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.31.1. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

First, the NERA study exhibits a number of what B&V would consider to be computational flaws in its assumptions about both inputs and outputs. Appendices D-1 and D-2 provide detailed explanations of these issues. On a theoretical basis, the B&V Report specifically included measures of all factors of production for electric utilities.

Second, the report used a more correct measure of output- customers and capacity that is also more consistent with the costs and inputs required to measure industry TFP. The NERA study made numerous assumptions that were necessary under the academic paradigm that may distort the measures of the inputs.

There are problems beyond those enumerated in the Reports, but the most important point is that B&V TFP analysis uses different measures of output and avoids the numerous assumptions required in the NERA report to measure inputs. In B&V's view its own approach results in a more robust and transparent estimate of TFP and one that is applicable to electric utilities which captures all of the input drivers.

46.1.1 For each difference identified by B&V, explain how this issue was handled by B&V and how it was handled by NERA. For each of these differences, also indicate the estimated effect on the resulting

TFP study. If this effect cannot be quantified, at minimum indicate the direction of the effect, increasing or decreasing the X-Factor.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.31.1.1. This response is specific to FBC.

B&V notes that it is not possible to make this comparison because the two studies are for different time periods and based on very different assumptions about the inputs required to provide electric service. It is also true that the NERA study only used data for the distribution function of delivery service. This is inconsistent with the inputs covered under the FBC PBR Plan.

In general, NERA did not include all costs of distribution (in its defense, the data base it used makes this difficult because of the vertical integration of the utilities studied and other data limitations).

Second, NERA used throughput as an output measure and that creates an entire set of other issues relative to: (1) the time required to factor out weather variations for residential and commercial sales; (2) the use of volumes in the industrial class served at transmission voltage as an output measure for distribution; (3) the impact of customer mix within the residential and commercial classes on distribution costs (electric heating customers require more capital investment in distribution but lower per unit costs); and (4) the system density (identified as one of the most critical variables for benchmarking utility costs).

Third, in developing the measures of input, critical costs were omitted from the analysis such as non-wage costs for labor, the cost of vehicles and equipment for distribution service, the costs of stores, the cost of outside services, and so forth. Outside services are particularly important to the extent that they include items such as right-of-way inspections, tree trimming and other important services to maintain a safe and reliable power system.

The end result is that there is no reasonable basis to compare the two studies. Conceptually, these points imply that the TFP estimate derived by NERA would be unreliable and would overstate TFP if services were outsourced, there were greater changes in the cost increases for post-retirement benefits than for wages and salaries, and so forth. Any attempt to comment on and quantify the totality of the differences in the studies would be speculative at best.

46.2 What are the differences in the B&V approach to calculating TFP that make it less academic and, presumably, more practical than the NERA approach relied on by the AUC?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.31.2.

The B&V TFP Studies use the most correct measures of output for electric transmission and distribution utilities. By using ex-post measures of inputs, all of the assumptions related to cost shares and weighting are eliminated (this is a benefit of the Kahn Method in general). The method is fully transparent without having to understand and reflect all of the economic issues such as indexing and developing regression equations. It applies the essential principle of Occam's razor that the simplest assumptions make for the best outcome. It is also the methodology used by other regulatory bodies such as the U.S. Federal Communications Commission.

47.0 Reference: Exhibit B-1-1, Appendix D2, p. 2

Measurement of TFP - Output

Page 2 of the B&V Report argues for a capacity output measure, customers and capacity, rather than a throughput measure such as kilowatt hours (KWhs) for the calculation of TFP growth.

47.1 How is the calculation of TFP growth using a capacity output measure affected when the size of the customers and their usage varies? For example, what is the consequence on the study if there are twice as many customers each using half as much gas or electricity compared to a study in which half as many customers use twice as much gas or electricity?

Response:

Under the B&V methodology, usage has no impact on factors of production and therefore has no impact on TFP. For smaller customers served by the utility's minimum electric distribution system, size has no impact on TFP. Adding larger customers that require additional capacity would increase the system capacity and the capital cost for the utility. The result is that both inputs and outputs grow. If the growth in inputs is faster than the growth in outputs TFP is negative. Given the scale economies related to adding capacity (per unit cost of larger electric components such as transformers have typically lower per unit of capacity added); it is more likely that TFP would be positive for adding the larger customer. It would also be positive for adding customers to the existing delivery system where more customers would be served from the same capacity for facilities such as substations, primary service lines and so forth. For customers added to the minimum system (residential for example) costs increase at a faster rate as density declines and TFP would, other things being equal, tend to be negative. As density increases in suburban areas TFP would be positive. If density increases in urban areas where it is more costly to install and maintain distribution underground delivery networks, TFP would likely be negative. To understand these issues, it is not only necessary to understand economics but also the engineering and operations of the electric delivery system. Typically, the experts performing TFP studies do not study the engineering and operating realities of utility systems as would be common for those who perform traditional cost of service analysis. This is just part of the shortcomings associated with purely academic studies being broadly applied in the real world of regulation.

47.1.1 How would the results of such studies compare to a TFP growth study using a throughput measure? In this context, which of these output measures, in the opinion of B&V, represents the most accurate measure of TFP, and why? Explain in detail.

Response:

B&V provides the following response.

Using MWHs as a measure of output, adding customers using more kWh than average to the system would increase TFP assuming that conservation by existing customers is not large enough to offset the growth in overall sales. That is, output would grow faster than inputs all else equal. However, the system is no more productive than the system would have been from adding a customer with lower volumes because the costs and inputs as measured by capacity are the same in either case for the smallest customers served by the smallest facilities used on the system. In the case of larger customers, higher load factors make the system look more productive than lower load factors even though the actual output of the system is identical to a system with lower load factor customers with the same demand.

The important point is that a MWH measure of output creates biased and unreliable results when measuring productivity. A simple example will illustrate this point. Two systems are identical in every respect - the same number of customers, the same density, the same miles of poles and conductor by size, voltage level, system configuration and age distribution. Their annual costs are identical in total each year for the last five years. The two systems have the same peak hour design load. The only difference is that the annual load factor for one system is higher than for the other. In this case TFP measured by customers and capacity would be the same. TFP measured by MWHs would be greater for the higher load factor system. The result produced is biased by the measure of output because volume does not cause costs. Similarly, if two systems had identical MWHs every year but different customer counts and densities and thus different costs the one with larger sales would have a higher TFP even if they served less customers and had less capacity. Again, this is a nonsensical result from the bias of MWHs as a measure of output. Using customers and capacity would eliminate this bias.

48.0 Reference: Exhibit B-1-1, Appendix D2, p. 2; Appendix D1, pp. 32-33

Productivity Improvement Factor (X-Factor)

48.1 Beginning at the bottom of page 32 and continuing on page 33, B&V take issue with NERA's use of class revenue to weight the output measure of kWh volumes. Did any of the experts referenced in the AUC's Decision 2012-237 take issue with NERA's use of class revenue to weight the output measure of kWh volumes? If so, please summarize what they said.

<u>Response:</u>

B&V has not analyzed the evidence of all parties related to every issue. It should be noted that the assumption employed by NERA is a common assumption for academic studies. Nevertheless, using class revenue to weight the output measure is wrong, both in terms of volumetric measures and in terms of weighting. Class revenue is an inadequate measure of output for distribution because industrial customers may not even use the distribution system as some will be served from the transmission system while others may own their facilities and therefore require different inputs for delivery service. This may account for lower revenue but there is no corresponding assumption related to lower inputs.

Further, it is likely that the revenues bear little relationship to costs except for the largest industrial customers because the residential revenue to cost ratio will be less than one while the commercial ratio will be greater than one. This is an example of assuming away another messy problem associated with the use of a volumetric basis for measuring output.

Finally, class revenues for electric customers include revenues associated with production and transmission resulting in an over statement of the impact of volumes on the distribution system since these costs represent a different percentage of the revenues for each class of customer. Distribution related costs would be a larger percentage of the bill for residential customers than for larger commercial customers for example. Urban and rural utilities will also have different percentages of distribution revenue for each class of customers given the higher costs of urban underground systems.

All in all, the use of revenues to weight output shares creates additional noise in the estimates of TFP.

Please also refer to the response to BCUC IR 1.45.1.

48.2 How would B&V weight the output measure of kWh volumes? Would such a weighting require cost allocations? If yes, how would these cost allocations be done?

Response:

Since there is no reasonable basis for using kWh volumes for measuring output, there is no need to weight volumes. As a result, B&V has not addressed the issue. B&V would note that for electric systems, measuring output based on kWh volumes would require more than a simple cost allocation to properly reflect appropriate weightings. At a minimum, it would be necessary to identify outputs and inputs by voltage level of service. Typically, residential and smaller general service customers use all components of the delivery service inputs, transmission, substations, primary facilities and secondary facilities. Larger customers make no use of secondary inputs at all. Even larger customers may not use primary facilities and some really large customers may own their own substation. By combining all of the sales as if they use all of the delivery inputs, the results of the analysis are biased by the distribution of customers by size and type when measuring the central tendency of TFP. This is just one form of bias and others related to system configurations such as overhead and underground service will also bias the TFP results.

49.0 Reference: Exhibit B-1-1, Appendix D2, p. 2; Appendix D1, p. 35

Productivity Improvement Factor (X-Factor)

49.1 On page 35 B&V reference the "most recent study by the Pacific Economics Group filed in Ontario." What are the results of that TFP growth study?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.34.1. This response is similar to FEI's response but is updated with the latest evidence that was not available at the time of response to FEI's BCUC IR 1.34.1.

The PEG Study filed as part of the electric distribution 4th Generation IR proceeding filed two studies of TFP based on nine years of data. The studies initially found TFPs of negative -0.05% and - negative 0.03%. Two new versions of this study were later published in May and September 2013. The TFP value in the most recent version (updated with 2012 data) is – negative 0.33%.

In B&V's view, the original and revised results represent an attempt to move to a more appropriate measure of output. Still, however, the capacity measure used was the actual coincident peak that has a number of shortcomings such as the fact that it varies from year to year based on weather or that it is not the peak that determines distribution costs or capacity requirements. Electric distribution costs are a function of customers and the non-coincident peaks of the customer classes and as diversity decreases for facilities closer to the customer, the customers' non-coincident peak.

49.2 Does the Pacific Economics Group also make a recommendation regarding the X-Factor? If so, what was that recommendation?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.34.2. This response is similar to the FEI response to that IR, however some minor differences were necessary in order update the response with the latest version (September 2013 version) of PEG's report..

Using a judgement-based approach, PEG is recommending an X-Factor value of zero percent plus a stretch factor of 0% to 0.6% (based on different efficiency cohorts).

50.0 Reference: Exhibit B-1-1, Appendix D2, pp. 8-10; Appendix D1, p. 34

Black and Veatch's TFP Model

"We have included all net plant for electric utilities as well as all costs including customer accounting costs and Administrative and General (A&G) overheads. It is important to include these costs because their exclusion would result in a substantial over-estimation of the productivity associated with electric delivery since the exclusion of many of the costs associated with plant maintenance and overhead costs associated with labor are included in the A&G cost category. Failure to include these costs under-estimates changes in the cost of inputs and, thus, over-estimates productivity of the labor resource. Further, there are significant costs associated with customer service and billing as well as general plant costs to support these activities" (Appendix D2, p. 9).

50.1 Regarding the costs mentioned above (net plant, customer accounting costs, A&G overheads, plant maintenance and overhead associated with labor, customer service and billing, and general plant) please explain if any cost allocations were necessary to include these costs in a TFP growth study.

Response:

No cost allocations were necessary to include these costs in a TFP growth study.

50.2 Identify any other cost allocations that were done as part of the B&V Report.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.35.2. This response is identical to the FEI response to that IR.

The method used by B&V required no cost allocations.

50.3 For any cost allocations, how were these allocations done? What methodology was employed?

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.35.3. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Not applicable. Please refer to the response to BCUC IR 1.50.2.

50.4 If any cost allocations were part of B&V's TFP growth studies, provide support in the economics literature regarding TFP growth studies to justify these cost allocations.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.35.4. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Not applicable. Please refer to the response to BCUC IR 1.50.2.

50.5 Provide a numerical example to demonstrate the effect on TFP growth of excluding cost categories that require cost allocations.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.35.5. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

Not applicable. Please refer to the response to BCUC IR 1.50.2.

51.0 Reference: Exhibit B-1-1, Appendix D2, pp. 3-4

Negative Productivity

Page 3 of the B&V Report argues that "(t)he negative productivity for capital is explained by the need to replace aging infrastructure."

Page 4 of the B&V Report states, "TFP is much more likely to be negative on a going forward basis than it is to be positive. This result occurs because the replacement of aging infrastructure, which is being undertaken by electric utilities across North America, adds cost unrelated to customer growth or additional capacity to serve non-coincident peaks (NCPs) or individual customer NCPs implying a negative TFP."

51.1 Is it not the case that aging infrastructure is always being replaced? Why is the replacement of aging infrastructure not incorporated into historical TFP growth measures? Why is it only in recent years that TFP growth has become negative? Please explain.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.37125.12. This response is similar to the FEI response to that IR, however some minor differences were necessary in order to respond appropriately for FBC.

B&V agrees that there is always some replacement of infrastructure in any electric utility system. Normal replacement is related to factors such as externally created damage, environmental effects and capacity expansions. This reactive replacement scenario would require an extended period of time to replace the entire system and enable a planned maintenance of system reliability. Beginning in the mid-1990s, electric utilities recognized that there were benefits for system safety, reliability and costs associated with the acceleration of infrastructure replacement under a comprehensive program. By the time of the TFP study, most electric utilities were engaged in such programs having identified the scope of required replacements based on factors such as transmission system needs, the age of substation equipment, the rate of deterioration of facilities such as poles and conductors and so forth. In addition where appropriate, utilities have taken steps to improve reliability through system betterment. The acceleration of infrastructure replacement under a comprehensive program assured a more rapid and comprehensive assessment of the replacement process. Many of the dollars associated with these programs represented a significant increase in annual capital expenditures above and beyond the normal capital budget prior to these programs. It is that change in the gross level of capital expenditures without the addition to the system of any capacity or new customers that drives TFP to be negative. The logic for this is simply that input costs increase and output remains the same. Zero change in output minus the increasing costs results in a negative TFP.

51.1.1 How does the extent of FBC's capital replacement compare to FBC's replacing aging infrastructure in the past period used to calculate TFP growth?

Response:

Over the past 10 years, a relatively larger portion of FBC's expenditures has been associated with transmission and distribution growth-related projects. This was due to higher levels of growth (as compared to historical growth rates) resulting in capacity deficits occurring in many areas of the system over a short period of time. Going forward, as T&D growth-related expenditures decrease, infrastructure replacement expenditures as a proportion of total capital expenditures will be higher even if the level of infrastructure replacement is unchanged.

For the period of 2007 to 2011, approximately 20 percent of total transmission and distribution capital expenditures were related to infrastructure replacement.

51.2 What is FBC's current need for replacing infrastructure compared to its historical pattern of infrastructure replacement? Is the anticipated capital replacement in the next five years different from its past capital replacement? How does FBC's replacement compare to that of the utilities used to calculate TFP growth?

Response:

FBC's current need for replacing infrastructure is higher compared to its historical pattern. Please refer also to the responses to BCUC IR 1.51.1.1 and BCUC IR 1.52.1. FBC is unable to comment directly on a comparison of the levels of infrastructure replacement investments at other utilities since this information is not immediately available; notwithstanding this, like most utilities FBC has a significant amount of infrastructure which was installed decades ago and which has either reached or will soon reach the end of its serviceable life.

B&V adds this is the same circumstance that utilities in the US are experiencing. The post WWII growth occurred over 60 years ago and the growth in the early 1970s is over 40 years ago. Utilities have begun systematic programs to replace and upgrade their systems based on both the age of facilities and the need to integrate new sources of generation such as wind farms and to respond to market needs for coordination of power supplies across much larger geographic regions. This has led to a combination of new investment in replacement of existing facilities and new facilities to deliver power unassociated with load growth.

51.3 Why has TFP growth become negative in recent years yet it has been positive on average for a longer historical period?

Response:

B&V states that the assumption implicit in the question that TFP has been positive is based on studies using throughput as a measure of output and there is no study as to what TFP values would be based on a longer historical period using the correct measure of output. For example, growing average use per customer during the historic period may cause TFP measured on kWh to be positive when this growth was served with existing facilities. In actuality, there may have been no real growth in output associated with customers or capacity. This would be an example of the bias associated with measuring output by kWh. The negative TFP results from infrastructure replacement as explained in the TFP Report.

51.3.1 Is it different from the capital replacement in the five years used for the TFP growth study? What are the consequences of your responses on the TFP relevant for FBC during its PBR plan?

Response:

B&V indicates that it is not possible to quantify the change in net plant associated with infrastructure replacement because infrastructure replacement costs are not reported as part of the financial reporting under FERC Form One. Therefore it is impossible to determine any impact on FBC's use of a 0.5% X-Factor in the PBR Plan.

52.0 Reference: Exhibit B-1-1, Appendix D2, pp. 3-4

Planned Capital

Pages 3-4 of the B&V Report discuss investment to replace existing facilities.

52.1 What percentage of FBC's planned investment over the PBR term is for capital replacement?

Response:

Approximately one-third (33%) of FBC's planned investment over the PBR term is for capital replacement.

52.1.1 How does this percentage compare to the percentages for the utilities that B&V used in its study to make a TFP growth recommendation for FBC? If these percentages are not the same, what is the implication for TFP growth and hence the X-Factor that B&V would recommend for FBC for the term of its PBR plan?

Response:

It is not possible to know the percentage of capital for infrastructure replacement in the B&V study. B&V recommended a judgmentally based X-Factor of zero as discussed in the evidence. This recommendation was based on the exclusion of CPCN capital.

53.0 Reference: Exhibit B-1-1, Appendix D2, p. 4

Negative Productivity

Page 4 of the B&V Report states, "The AUC rejected the negative measure [of TFP] because the output measure was throughput based..."

53.1 Provide the specific reference in AUC Decision 2012-237 to support this statement.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.39.1. This response is identical to the FEI response to that IR.

This statement is not a quote from the AUC Decision 2012-237. Rather, it is distilled from the adoption of a term that excludes economic considerations associated with downturns that result in negative TFP values. See for example the discussion at paragraphs 316, 381, 384 and 391 of the AUC Decision which are reproduced below.

> **316**. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.[338] The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

> **381**. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

384. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

53.2 What output measure would B&V have used instead of the throughput measure that the AUC rejected? What would have been the effect on the calculation of TFP growth?

Response:

B&V used a more theoretically and practically correct measure of output – customers and capacity - thus the longer time period of analysis is not required and the results of the TFP study would reflect the changes in outputs and inputs properly. Based on our TFP analysis, the TFP would be negative instead of positive and would be logically consistent with the underlying industry factors discussed in the TFP Report.

53.3 Is it the case that while throughput measures would have declined ("The economic downturn that had reduced the kWh measure of output..." (page 4)), B&V's preferred output measure, customers and capacity, would not have declined or would have declined by much less than the throughput measure?

Response:

B&V provides the following response.

Yes. A decline in customers may occur over time as part of macroeconomic conditions such as the movement of population from one region to another or the loss of major employment in a particular service area. This would also reduce capacity requirements over time as well. This type of economic development trend is not a short term impact and is not related to the business cycle although that may accelerate the trend.

53.3.1 Would the average TFP growth for the last nine-year period still have been negative using B&V's preferred output measure? If still negative, would it have been larger than the TFP growth calculated using a throughput measure of output?

Response:

B&V has not studied the nine-year period and cannot answer the inquiry with any degree of certainty. However, we would hypothesize that TFP would still have been negative just based on our understanding of when infrastructure replacement programs began on a broad scale. We have no basis for discussing a throughput-based result. However, it is likely that a throughput measure would have grown more slowly than the customer capacity measure of output. When utility systems were adding many more new customers and capacity coupled with slower volumetric growth as a result of conservation, the TFP would likely be lower than the actual TFP using customers and capacity as the output measure.

54.0 Reference: Exhibit B-1-1, Appendix D2, pp. 8

TFP Growth Study

Page 8 of the B&V Report stated that they used data for their TFP growth study for the latest available five year period, 2007-2011.

54.1 What is the theoretical basis for using the latest available five year period for a TFP growth study? Please provide references to the literature.

<u>Response:</u>

B&V provides the following response.

The theoretical basis for using a five year study period relates to several issues.

First, by using a period closer in time to forecast the expected TFP for the plan period, the estimate fairly reflects the adoption and implementation of prior technological changes that have occurred and represents the mature nature of the industry.

Second, as discussed in Appendix D-1, the use of volumetric output data would require a longer time period to average out weather impacts on TFP estimation. Further, it is assumed in most studies that volume is a measure of output, thus, increasing the required study period. Using the more correct and more stable estimate of output-customers and capacity, the necessity of using a longer period to develop a measure of central tendency is not required.

Third, the longer study periods would overstate the impact of technological change on the expected TFP value during the regulatory control period when the technological change has been fully implemented, as is the case for activities that occurred in the earlier portions of the period and are fully implemented in more recent data on an industry wide basis. Given that the electric industry is a mature industry with common practices and methods, it is reasonable to assume that TFP gains based on the new technologies introduced in the past have been fully implemented in the current period. To the extent a new technology becomes available during the regulatory control period, the adoption of that technology as soon as feasible is part of the incentive aspect under PBR. Both FEI and its stakeholders are protected by the balanced ESM in the overall PBR plan.

From a theoretical perspective, the estimates of TFP relate to the production function which has a short-run and a long-run dimension. Any number of basic economic texts explains the elements of the short-run and long-run. In particular, the concept of the short-run is a period when all factors of production are fixed. In the long-run at least some factors of production can vary as would be the case for a five-year PBR Plan. These issues are discussed in the electric productivity report prepared by B&V related to the term of the included TFP study. The use of the near-term reflects the long-run considerations of some fixed factors of production. In addition, the use of the shorter time period is appropriate because it reflects the full implementation of technology changes that are reflected as productivity gains in historic periods. See for example the discussion of the AUC report in Appendix D-1. There is no basis for using 20 or 30 years of data when output is properly specified as in the TFP study for electric utilities presented in Appendix D-2.

54.2 In B&V's opinion, what is the reason for using the latest available five year period for the TFP growth study?

Response:

Please refer to the response to BCUC 1.54.1.

54.3 What would have been the consequences on the TFP growth study results, presented in Table 1, Summary of TFP Results, page 11, if a longer period, for example, 10 or 20 years, had been used? If a precise estimate cannot be given, indicate the direction of the change on TFP growth given what B&V knows about the historical trends in TFP growth.

Response:

Please refer to the response to BCUC IR 1.53.3.1. The same answer applies to longer periods.

55.0 Reference: Exhibit B-1-1, Appendix D2, Table 1 - Summary of TFP Results, p. 11

TFP Summary Results

55.1 Provide a similar table for each of the five years in the B&V TFP growth study.

Response:

B&V provides the following response.

It is not possible to provide a result for each of the five years because one year is the base year. The following table provides the requested information.

Average Electric Utility TFP Results

TFP Measures	2008	2009	2010	2011	2008-2011 Average
Electric Customers/Substation Capacity weighted 40%/60%	-0.043686674	-0.074060903	-0.064445973	-0.064722485	-0.061515414
Electric Customers/Substation Capacity weighted 60%/40%	-0.043495410	-0.074485455	-0.065102836	-0.065741181	-0.061990974
Customer Measure	-0.043313292	-0.074852901	-0.065666686	-0.066596210	-0.062390638
Capacity Measure	-0.037381650	-0.058527847	-0.037780561	-0.024773065	-0.039478702

56.0 Reference: Exhibit B-1-1, Appendix D2, p. 9

TFP Study

Page 9 of the B&V Report states that they include “all net plant for electric utilities as well as all costs including customer accounting costs and Administrative and General (A&G) overheads’ in their TFP growth study. B&V argue that excluding these costs would result in “a substantial over-estimation of the productivity associated with electric delivery...”

56.1 Since the TFP study is designed to calculate TFP growth and not the level of TFP, explain in detail how excluding these costs would affect the calculation of TFP growth as opposed to productivity as stated at the top of page 9. Use a numerical example if that is helpful.

Response:

This question is identical to FEI’s 2014-2018 PBR Application, BCUC IR 1.43.1. This response is identical to the FEI response to that IR.

B&V states that to the extent that these costs change at a different rate than other costs the effective rate of change in input costs will be different. Since TFP is change in output minus change in input the TFP will change. The over estimation of productivity occurs because the input related to items such as vehicles and tools as well as a portion of the labour costs specifically related to distribution are excluded and some of those costs have changed dramatically over time. More simply, it is impossible to produce capacity and customers without the inputs that were excluded by NERA in the case of the AUC proceeding. If you exclude inputs and assume the same output, then TFP logically increases.

57.0 Reference: Exhibit B-1-1, Appendix D2, Table 1, Summary of TFP Results, p. 11

TFP Results

57.1 What, precisely, is B&V's recommendation for TFP growth for FBC in this proceeding?

Response:

B&V would recommend a TFP value of minus 5.5%. Refer to Exhibit B-1-1, Appendix D-2, Table 1 for the range of values from the study. The average of the values was minus 5.5%.

57.2 What, precisely, is B&V's recommendation for an X-Factor for FBC in this proceeding?

Response:

B&V recommends that the X-Factor for FBC should be zero based on the overall terms of the proposed PBR Plan. The 0% X-Factor is inclusive of a stretch factor.

57.3 Explain what adjustments B&V recommends to the TFP growth results to determine an X-Factor, and explain in detail why it is appropriate to make these adjustments.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.44.3. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

B&V makes no specific adjustments to the TFP factor. B&V's recommended X-Factor is based on several features of the overall plan that we believe moves the negative TFP closer to zero. The 0% X-Factor would include a stretch factor as well. The TFP results from the study include all new capital during the study period. Based on our review of the factors outside the PBR such as CPCN capital and other provisions we felt that even zero is a stretch.

57.4 In Exhibit 1, Productivity Improvement Factor Proposals in Alberta, in Appendix D1, PBR Jurisdictional Benchmarking Report, the proposed X-Factors from the four utilities range between -1.0 and -2.0. In B&V's opinion, what explains the difference between these recommendations and B&V's calculations in Table 1, Summary of TFP Results, on page 11 of Appendix D2, which are all very close to zero. Be specific as possible.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.44.4. This response is similar to the FEI response to that IR, however some differences were necessary in order to respond appropriately for FBC.

The values are expressed in different units. The benchmark values are percentages while the TFP reports the values as decimals. The negative 1-2% range from Alberta is closer to the TFP values for electric utilities of between -4% and -6% in the B&V TFP Study than is implied by the question. The main differences between the Alberta values and the B&V TFP study values include the sources of data and the output measures. These estimates relied on adjustments to other studies using the fundamentally biased kWh measure of output. As discussed more fully in Appendix D-1, there are other errors in the development of the TFP values that make the results unreliable from a practical perspective.

58.0 Reference: Exhibit B-1, Table A1-1 Summary of 2014 PBR Plan Proposal, p. 2

58.1 Regarding the section of the table on Controllable Expenses – Capital, provide a numerical example to show how this capital expenditure deadband of 10 percent would work.

Response:

The total capital spending under PBR for 2014 of $72.758 million, as set out in Exhibit B-1, Figure B6-3 on page 59 is used for illustrative purposes. It is also assumed for ease of illustration that no cost driver adjustments for actual customer count and service line installations are required.

If actual capital spending is below 90 percent of $72.758 million (i.e. $65.482 million) an adjustment would be applied to the formula-based capital expenditures spending level in the year.

Assume for this example that actual capital spending is at 85 percent of the capital spending level under PBR, or $61.844 million.

The difference between 90 percent and 85 percent ($65.482 million - $61.844 million = $3.638 million) is deducted from the formula-based capital expenditures additions for 2014 and are incorporated in the rate base to establish revenue requirement calculations for future years; that is, the opening rate base for the following year will reflect the lower amount. The calculation of the formula-allowed capital spending amount for rate calculations in future years is unaffected by this adjustment.

The adjustment of $3.638 million would be deducted from the capital accounts (for ratemaking) in the same proportions as included in the $72.758 million before the adjustment.

58.2 Discuss in detail the incentives for the company that would result from "(l)imited rebasing of capital...if annual capital expenditures are above or below the formula-based amount by more than 10 percent."

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.45.2. This response is similar to the FEI response to that IR, however some changes were made in order to respond appropriately for FBC.

The proposed 10% dead-band adjustment to capital expenditures variances reduces the potential incentive power of the PBR by limiting the amount of capital savings that may be pursued in each year to 10% of the formula determined capital.

58.2.1 In this context, explain what the "formula-based amount" is and how it is calculated. Are there non-formula-based amounts of capital? If so, please identify these and explain how they are calculated.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.45.2.2. This response is identical to the FEI response to that IR, with the exception of the name change to FBC.

Formula-based capital expenditures are the capital expenditures in the Growth, Sustainment and Other categories calculated according to the I-X formulas described in Section B6.2.5.2 of this Application. For clarity, the formula-based capital expenditures that the 10% dead-band will apply to will be the amounts calculated based on the adjusted cost drivers that incorporate the latest forecasts, specifically, average customers and service line additions.

59.0 Reference: Exhibit B-1-1, Appendix D5, p. 3

Efficiency Carry-Over Mechanism

The company provides an illustration of what it calls the end-of-term efficiency sharing mechanism.

59.1 Explain how the allowed O&M per PBR formula (line 4) is calculated.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.46.1. This response is similar to the FEI response to that IR.

As noted in the question the ECM example presented in Appendix D5 was intended to be illustrative.

The allowed O&M per PBR formula is calculated as described in Section B6.2.4.2 (the same calculation is used for the ECM as is used to set rates) with currently forecast amounts provided in Table B6-5 of the Application on the "Total O&M Under PBR" line. The amounts from Table B6-5 are the gross O&M amounts before capitalized overhead. The amounts shown on Page 3 of Appendix D5 are based on the same gross O&M amounts net of 20 percent capitalized overhead. The amounts to be used in the ECM calculations will be inclusive of any adjustments for actual cost driver results.

59.2 What does it mean, "net of OH Capitalized" (line 4)? What is the consequence of netting out of OH Capitalized on the earnings sharing amount calculated on line 16? What is the justification for this? Explain.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.46.2. This response is similar to the FEI response to that IR however some minor differences were necessary in order to respond appropriately for FBC.

The mechanics and justification of capitalized overhead are described extensively in Exhibit B-1-1, Section D3.7 of this Application. For the table in Exhibit B-1-1, Appendix D5, page 3, "net of OH Capitalized" means Total Gross O&M as calculated in Table B6-5 less 20 percent of this amount which relates to overheads capitalized. The 20 percent amount is simply reallocated from O&M to capital to represent the overhead operating expenses attributable to capital work. Consistent with historical and current practice, the actual amount for the 20% overheads capitalized will be recorded at the forecast amount, so there will be no variances in either the capital additions or O&M specifically resulting from capitalized overhead in the ECM calculation. This treatment of Overheads Capitalized is the same treatment that FBC has applied to Overheads Capitalized in the 2007-2011 PBR as well as in the 2012-2013 RRA. Since no earnings variances will be attributable to Overheads Capitalized differences, the ECM illustrative example in Appendix D5 has used the O&M amount net-of-Overheads Capitalized as the starting point.

59.3 Explain how capital expenditures allowed per PBR formula (line 10) are calculated.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.46.3. This response is similar to the FEI response to that IR.

As noted in the question the ECM example presented in Exhibit B-1-1, Appendix D5 was intended to be illustrative.

The allowed capital expenditures per PBR formula will be the total amounts of formula-based capital expenditures in the Growth, Sustainment and Other categories. Due to an oversight, the illustrative example provided in Appendix D5 does not tie in to the correct line item on Table B6-7. The calculations of the formula-based amounts are described in Section B6.2.5.2 and the current forecast of allowed amounts is provided in line 15 of Table B6-7 of the Application labelled "Formulaic Capital". The same calculation is used for the ECM as is used to set rates. The amounts to be used in the ECM calculations will be inclusive of any adjustments for actual cost driver results.

FBC is attaching a corrected version (see Attachment 59.3) of the Illustrative ECM Example provided in Appendix D5. The table in Appendix D5 inadvertently utilized Line 21 of Table B6-7, which is total capital, including capital tracked outside of the PBR formula instead of line 15, which as discussed above reflects only the formulaic capital. The revision does not affect the ECM methodology.

59.4 If the Commission were to allow an X-Factor different from the one proposed by FBC, how would the example on page 3 change? Explain in detail for both an X-Factor higher and lower than the one proposed by FBC.

Response:

This question is identical to FEI's 2014-2018 PBR Application, BCUC IR 1.46.3. This response is similar to the FEI response to that IR however some minor differences were necessary in order to respond appropriately for FBC.

The X Factor that is approved will be reflected in the calculation of the ECM.

A higher X-Factor than the one proposed by FBC would result in a reduction to the "Total O&M Under PBR" amounts in Table B6-5 discussed in the response to BCUC IR 1.46.1 and the "Total Capital Under PBR" line in Table B6-7, discussed in the response to BCUC IR 1.59.3. These reductions would flow into the net of capitalized overhead O&M value in Exhibit B-1-1, Appendix D5, Line 4 of the table on Page 3, and the reductions in formula-based capital would flow into Line 10 of the table on Page 3 of Appendix D5. Assuming the actual O&M and capital spending is the same, flowing these X-Factor related reductions through the Efficiency Carry-Over Mechanism table would result in a reduction to the incremental benefits sharing amounts in the table and, further, a reduction in the amount of revenues FBC will collect from or return to customers as part of the ECM benefits Phase-Out.

The opposite holds true in the case where the X-Factor is lower than the one proposed by FBC in this Application.

C. SERVICE QUALITY INDICATORS

60.0 Reference: Exhibit B-1, pp. 68-69, Table B6-8: Proposed 2014 PBR SQIs;

Exhibit B-1, p.40, Table B6-1: Summary of 2014 PBR Plan Proposal; and

Exhibit B-1-1, Tab D, Appendix D6, pp. 11-12

Service Quality Indicators (SQIs)

FBC proposes "SQIs (5 SQIs with a target benchmark and informational measures) are proposed that deal with emergency response, customer service, employee safety and system reliability."

(Exhibit B-1, p. 40)

In Exhibit B-1, Table B6-8, p.69, FBC identifies the following SQIs as informational indicators:

1. System Average Interruption Duration Index (SAIDI) – Normalized;
2. System Average Interruption Frequency Index (SAIFI) – Normalized;
3. All Injury Frequency Rate (AIFR) which is the sum of lost time injuries (LTI) plus medical treatment injuries (MT);
4. Customer Satisfaction Index (CSI).

In Exhibit B-1-1, Appendix D6, pp.11-12, FBC identifies the following SQIs as discontinued indicators:

1. Generator Forced Outage Rate;
2. Residential Connections Completion Time;
3. Residential Extensions Quoting Time;
4. Residential Extensions Completion Time;
5. Injury Severity Rate; and
6. Vehicle Incident Rate.

60.1 Considering the need for benchmarking data,

60.1.1 Please explain why the reliability indices are now considered to be informational indicators and calculated on a three year rolling window.

Response:

Please refer to the response to BCUC IR 1.68.9 for discussion of why the SAIDI and SAIFI reliability indicators are now proposed to be informational indicators. As indicated in that response, there may be external factors that can influence the results beyond the Company's control, making the task of setting an appropriate benchmark challenging.

With regards to the use of a three year rolling average, FBC recognizes the variation in the SAIDI and SAIFI results that may occur annually. To adjust for this variation, FBC proposes the use of a three year rolling average which would smooth out the annual results, providing for a longer term indicator of any trends that may be developing.

60.1.2 Please explain why the reliability indices, other than SAIDI and SAIFI, are now considered to be discontinued indicators.

Response:

The discontinued reliability indicator is Generator Forced Outage Rate. Table D6-1 in Appendix D6 of Exhibit B-1 sets out the criteria FBC used in designing and selecting SQIs for its 2014-2018 PBR Plan. First, FBC considered that the SQIs it selected must represent a service or a service attribute that customers value. The Generator Forced Outage Rate metric, unlike SAIDI and SAIFI, does not directly impact customers and the electric service they receive, and for that reason was discontinued.

61.0 Reference: Exhibit B-1, pp. 68-69

Table B6-8: Proposed 2014 PBR SQIs

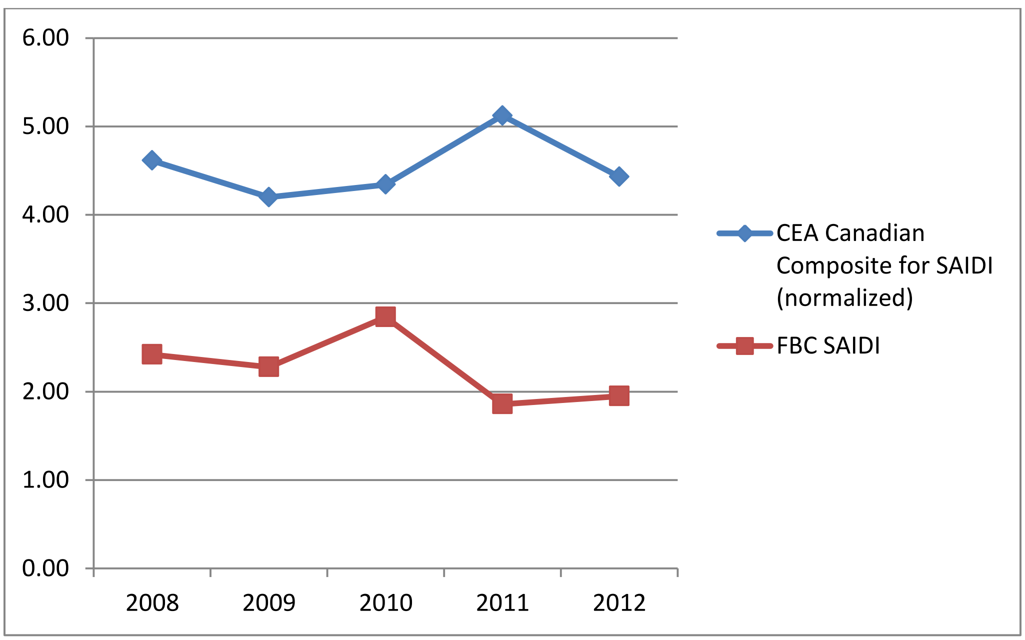
Reliability Indices

61.1 Please provide benchmarking data for System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), All Injury Frequency Rate (AIFR), and Customer Satisfaction Index.

Response:

FBC has provided the below CEA comparison data for SAIDI, SAIFI and AIFR. FBC is not able to provide any benchmarking data for its CSI, as the survey was specifically designed for FBC and therefore there is no other comparator information available.

SAIDI



SAIFI

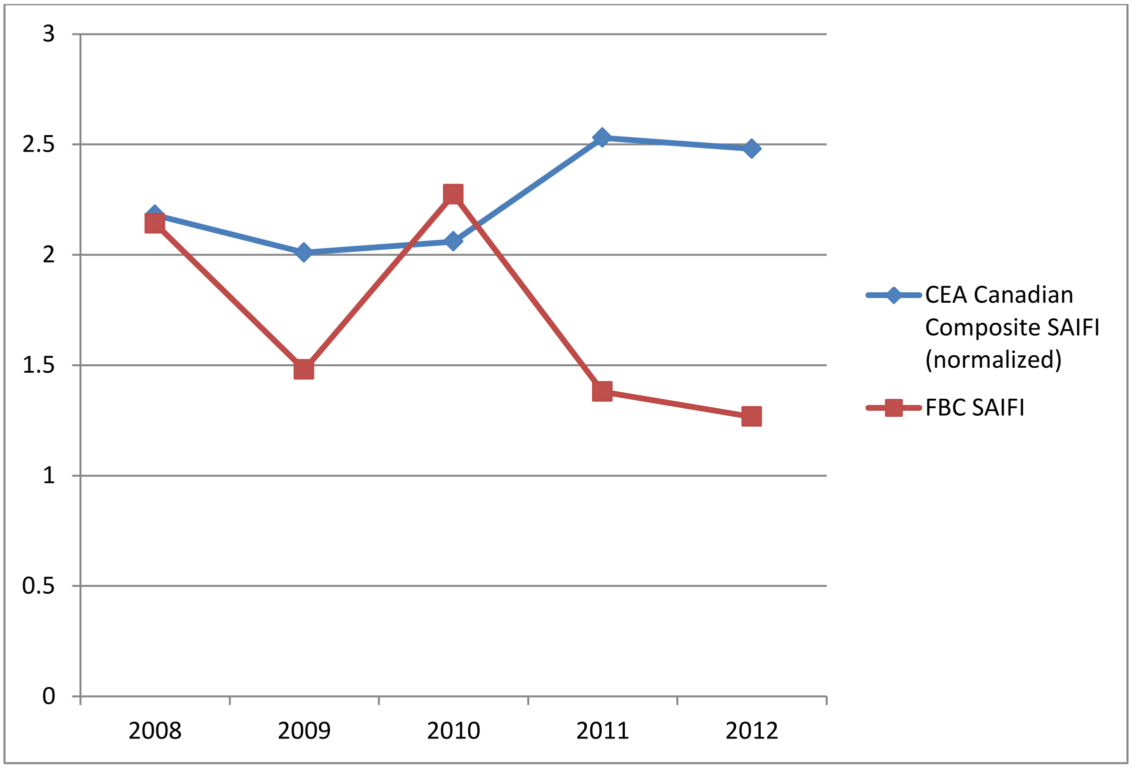
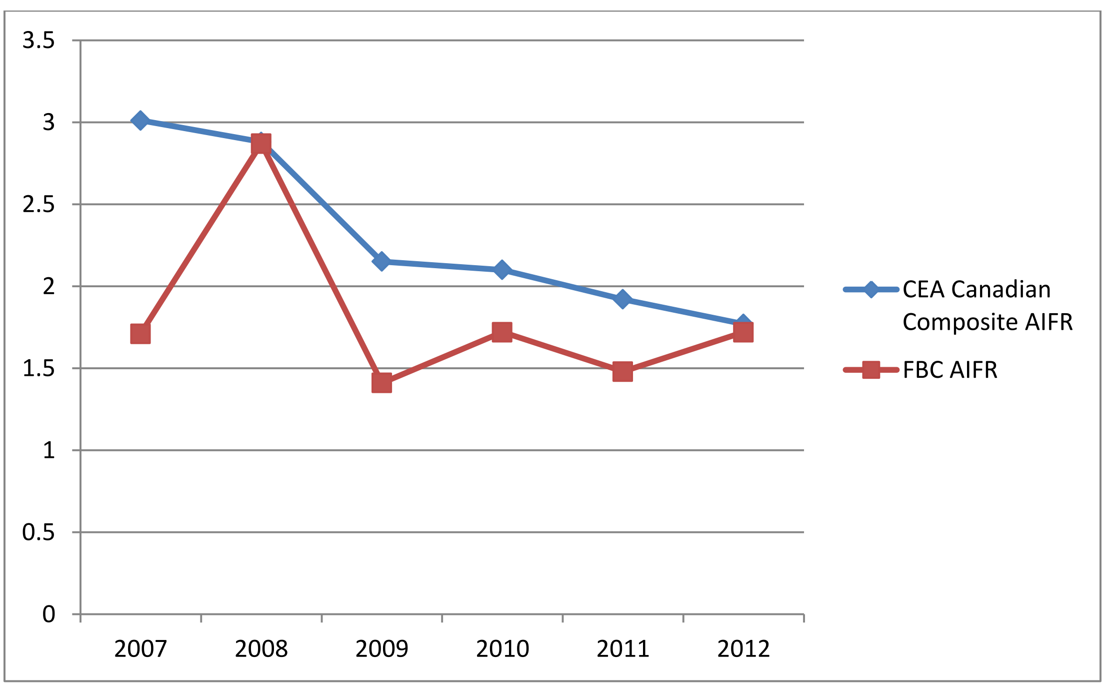


Figure BCUC IR 1.61.1c AIFR



61.2 Do SAIDI and SAIFI distribution-system reliability indices in the Application only apply to distribution customers? Please explain.

Response:

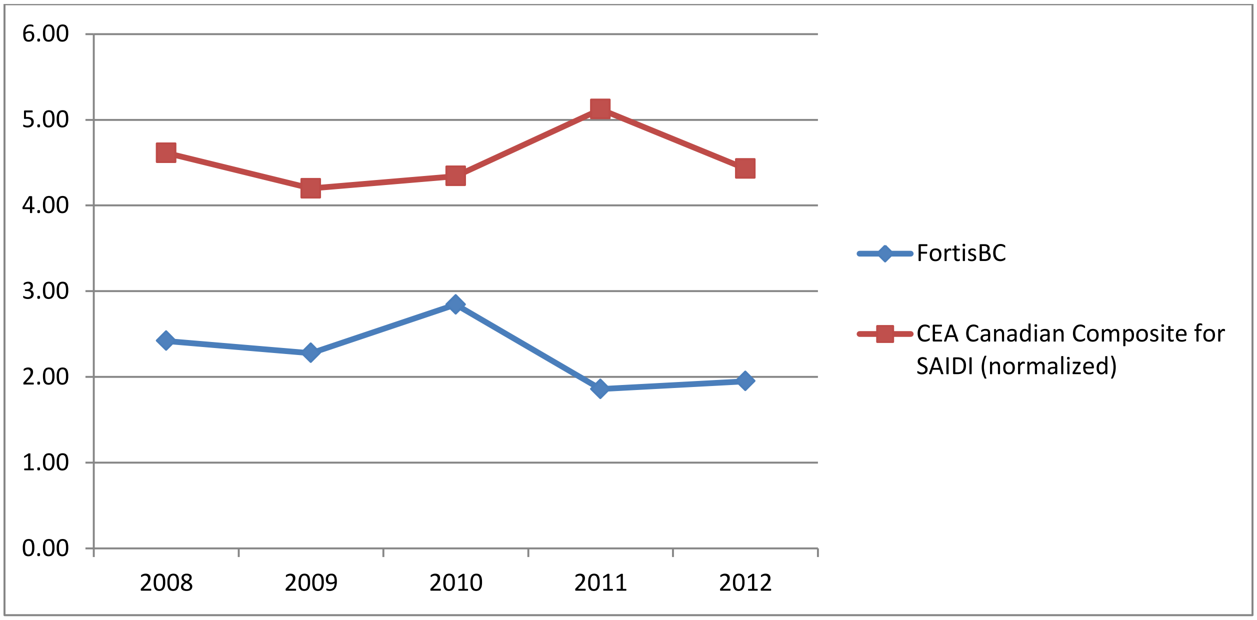
No. The proposed SAIDI and SAIFI reliability SQIs include FBC's transmission and distribution systems.

61.3 Provide a line graph of SAIDI trends over the last five years plotted against Canadian Electrical Association (CEA) and/or Electric Power Research Institute (EPRI) SAIDI values including the median value, and the upper and lower quartiles for the same period to demonstrate the 2013 value of SAIDI going forward into PBR.

Response:

Please refer to the below figure comparing FBC normalized SAIDI over the past five years with CEA normalized SAIDI for the same time period. FBC is not able to provide a comparison to EPRI SAIDI values as FortisBC is not a member of EPRI. Most EPRI reports are only available to members and are copyrighted. FortisBC was unable to locate any recent, publicly available reliability statistics produced by EPRI.

FortisBC Normalized SAIDI versus CEA Normalized SAIDI (2008-2012)



Momentary Average Interruption Frequency Index (MAIFI) is the ratio of the annual number of momentary interruptions to the number of consumers.

61.4 Considering the sensitivity of electronic equipment, please explain why MAIFI, the average number of momentary (less than five minutes) interruptions per consumer during the year, was not included in the proposed SQIs.

Response:

MAIFI can be a difficult measure of reliability to compare across utilities and even within a single utility, as momentary interruptions are typically caused by transient faults, such as lightning strikes, vegetation or animals contacting a power line. As a result, year over year results are difficult to compare as momentary interruptions may be much higher or lower in a given year due to a large number of variables outside utility control (frequency of lightning storms or high wind events, etc.).

Additionally, prior to the full implementation of Advanced Metering Infrastructure (AMI), FBC has a very limited ability to detect and hence report momentary outages. Currently, FBC has a significant number of field devices, such as distribution reclosers, which can trip and reclose for a transient fault (such as lightning or an animal contact) – yet FBC has no indication that this event has occurred. This is because there is no communications and hence no monitoring of these field devices. On this basis, it would be difficult for FBC to meaningfully report the events that make up the MAIFI. Once AMI and an Outage Management System (OMS) are fully deployed, only then would the necessary monitoring equipment (advanced meters at each customer premise) and systems be capable of accurately reporting momentary customer outage events. Since the AMI and OMS projects will only be completed near the mid to end of the PBR term, it would be inappropriate to report on MAIFI at this time.

61.5 Directive 26 of the BCUC's decision on BC Hydro's 2004-2006 Revenue Requirement Application[14] requires annual reporting of reliability indices for transmission. The indices being reported are:

DPUI a measure of overall bulk electricity system performance in terms of a composite index of unreliability expressed in system minutes during a year. It takes into account all forced and planned outages except interruptions attributed to generators;

SARI a measure of the average restoration time, in hours, for each transmission delivery point;

T-SAIFI-MI a measure of transmission interruptions of less than one minute in duration that a delivery point experiences during a given period;

T-SAIFI-SI a measure of transmission interruptions of one minute or more that a delivery point experiences during a given period;

T-SAIDI a measure of the average total interruption duration, in hours that a delivery point experiences during a given period.

61.6 As FBC has transmission customers, why is FBC not proposing to report the same indices as well as transmission information from the CEA reports not included for the purposes of the PBR Application?

Response:

When compared to BC Hydro, FBC has very few transmission customers – currently only four. These customers are connected to the same transmission network that supplies the rest of

[14] In the Matter of an Application by BC Hydro and Power Authority of its 2004/05 to 2005/06 Revenue Requirements, Decision dated October 29, 2004.

FBC's customers and hence are captured in the proposed reliability statistics. All of these transmission customers have intervened in recent FBC regulatory proceedings in some way or another, and to the Company's knowledge, have not expressed significant security of supply concerns. On this basis, FBC does not consider there to be any substantial benefit from producing "transmission only" reliability statistics.

61.6.1 Does FBC report its transmission reliability data to North American Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC)? If so, would FBC please provide a copy of the report?

Response:

No. FortisBC is not required to report its transmission reliability to NERC or WECC.

In Table B5-1: Jurisdictional Comparison, Exhibit B-1, p. 37, FBC shows a comparison of SQIs, K-Factor, Y-Factor, and Z-Factor with Alberta Electricity and Natural Gas and OEB 4th Generation IR (Electricity);

In Exhibit D-9, Proposed PBR Framework for FEI and FBC, p. 57, FBC proposes the metrics for Service Quality Indicators are: safety, customer service and reliability.

61.7 Please describe and compare the reliability metrics proposed by the AUC and Rule 002 in Alberta next to those proposed by FBC.

Response:

Please refer to the below table which compares the reliability metrics set out in the AUC's Rule 002 and FBC's Proposed SQIs.

Reliability Standard	FBC Proposed SQIs	AUC Rule 002
System Average Interruption Frequency Index (Normalized)	Yes	Yes
System Average Interruption Frequency Index (including Major Events)	Not Proposed	Yes
System Average Interruption Duration Index (Normalized)	Yes	Yes
System Average Interruption Duration Index (Including Major Events)	Not Proposed	Yes
System Average Interruption Duration Index of worst-performing circuits on the system	Not Proposed	Yes

For the proposed 2014-2018 PBR period, FBC considered a number of criteria in selecting the appropriate reliability SQIs to track. These criteria are set out in Table D6-1 in Appendix D6 of Exhibit B-1. An important criterion in selecting the appropriate reliability metrics is controllability. FBC has little control over major events that impact the reliability of its transmission and distribution systems, and therefore FBC is proposing to report on normalized and SAIDI and SAIFI for the proposed PBR period.

Further, in developing the suite of SQIs for the proposed PBR period, FBC sought not only to select the appropriate measures but also the optimal number of measures (i.e. how many). As indicators are an important communication tool of the overall service level to customers, FBC believes it is most appropriate to focus on a few key SQIs that reflect the overall areas of importance to the Company and its customers.

61.8 Please describe and compare the reliability metrics proposed by OEB 4th Generation for Electricity next to those proposed by FBC.

Response:

Please refer to the below table which compares the reliability metrics as proposed in the OEB's 4th Generation Incentive Regulation for Electricity and FBC's Proposed SQIs.

Reliability Standard	FBC Proposed SQIs	OEB 4th Generation IR
System Average Interruption Frequency Index (Normalized)	Yes	Not Proposed
System Average Interruption Frequency Index (including Major Events)	Not Proposed	Yes
System Average Interruption Frequency Index (Loss of Supply)	Not Proposed	Yes
System Average Interruption Duration Index (Normalized)	Yes	Not Proposed
System Average Interruption Duration Index (Including Major Events)	Not Proposed	Yes
System Average Interruption Duration Index (Loss of Supply)	Not Proposed	Yes

For the proposed 2014-2018 PBR period, FBC considered a number of criteria in selecting the appropriate reliability SQIs to track. These criteria are set out in Table D6-1 in Appendix D6 of Exhibit B-1. An important criterion in selecting the appropriate reliability metrics is controllability. FBC has little control over major events that impact the reliability of its transmission and distribution systems, and therefore FBC is proposing to report on normalized and SAIDI and SAIFI for the proposed PBR period.

Further, in developing the suite of SQIs for the proposed PBR period, FBC sought not only to select the appropriate measures but also the optimal number of measures (i.e. how many). As indicators are an important communication tool of the overall service level to customers, FBC believes it is most appropriate to focus on a few key SQIs that reflect the overall areas of importance to the Company and its customers.

62.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.1.1 Emergency Response Time, p. 4

Emergency Response Time

62.1 Please explain how AMI and the Outage Management System (proposed for 2015) may influence this SQI.

Response:

As the Company currently has limited visibility on the status of the distribution network downstream from distribution substations, existing outage management processes rely primarily on customers contacting the Company by phone to advise of local outages in their area. The Emergency Response Time SQI measures the time elapsed from the initial identification of an outage (typically via a customer call) to the arrival of FBC personnel on site at the trouble location. An Outage Management System (OMS) would allow near-real time operational data from an AMI system to be used to map outages and determine the location and estimated number of customers impacted by a particular outage, removing the need for customers to contact the Company to advise of an outage.

It is expected that the implementation of an OMS will improve the accuracy of the Emergency Response Time SQI by providing the Company with immediate notification of an outage, including the location and estimated number of customers affected. Although the Company will have more immediate notification of outages, and will likely be able to more quickly respond, it is difficult to estimate the extent to which an OMS may impact the results measured under this SQI. The increased accuracy of the actual outage start time and granularity of the information provided by an OMS may in fact negatively impact the results measured under this SQI as compared to the results obtained through the current process of relying on customer contact as the start time for outages and outage response.

63.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.2.2 First Contact Resolution (FCR), p. 6

Service Quality Measurement (SQM) Group

63.1 Please provide the estimated cost of engaging SQM Group to perform this service.

<u>Response:</u>

SQM currently charges $2.20 per survey, including transcription of all verbatim. Surveys are conducted by automated dialer and IVR. Expected costs for this service are detailed below.

Annual Survey Costs	
94 Surveys per month	
1,128 Surveys per year	
Cost per survey is $2.20	
Annual cost to survey 1,128 x $2.20/survey	$2,482
Annual Administrative Costs	
Maintenance	$335
Web Portal Licences	$1,495
Total Annual SQM Costs	$4,312

63.2 Does any other electrical utility employ SQM Group to provide this service?

<u>Response:</u>

SQM provides contact centre evaluations for over 450 clients across North America, including many energy utilities.

Electric/Combined Utilities	Other Energy Providers
American Electric Power	FortisBC Energy Inc.
Arizona Public Service	Direct Energy
BC Hydro	Enbridge Gas Distribution
Brantford Hydro	Suncorp
Enmax	

Electric/Combined Utilities	Other Energy Providers
PacifiCorp	
Exelon	
Florida Power	
Idaho Power	
London Hydro	
Manitoba Hydro	
Northeast Utilities	
Pacific Power	
Sierra Pacific Power	
Toronto Hydro	
TransAlta	

63.2.1 If so, please supply the names of the utilities.

Response:

Please refer to the response to BCUC IR 1.63.2.

63.3 Please provide the cost of FBC's providing its own electric customer service survey data.

Response:

The Company has not thoroughly investigated the costs associated with using its own employees to gather post-call customer service feedback. FBC has never conducted phone surveys itself, but rather relies upon specialized third party research vendors to obtain customer feedback. This approach ensures impartiality, and provides FBC with affordable and directly comparable benchmark information.

As detailed in response to BCUC 1.63.1, total annual costs for SQM services is $4,312. For FBC to pursue its own post-call contact centre research strategy, the Company would need to make an investment in a suitable automated dialer and data collection system, a new reporting system to present and analyze customer feedback, and incur higher operating expenses to maintain these new systems, accommodate the additional volume of outbound calls, and time needed to transcribe customer verbatim. FortisBC is confident that the outsourced feedback is more cost effective than using internal resources.

63.3.1 Provide the degree of improvement if SQM is used instead of FBC providing its own electric customer service survey data.

Response:

SQM research has only been in place at FBC since April 2013. As discussed in the response to BCUC IR 1.63.3, establishing its own electric customer service survey is likely to be more expensive and would fail to deliver key advantages available from the third party solution. The primary advantages of using SQM relate to benchmarking and expert opinion. SQM brings expertise garnered from years of contact centre customer satisfaction work with over 450 clients. Access to their research ensures that FBC can confidently compare its contact centre results with FEU, as well as other North American energy providers and industries; it provides coaching level input for our CSRs; and helps management prioritize enhancements or changes to ensure our service quality cost effectively meets customer needs today and as they evolve.

63.3.2 What will become of the FBC staff currently performing the electric customer service survey?

Response:

There are no employment repercussions associated with the adoption of SQM research services because FBC has never conducted its own surveys.

64.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.2.3 Billing Index, pp. 6-7

AMI Impact

64.1 Assuming the AMI Project is approved and implemented on schedule, please explain how AMI will influence this SQI, as both accuracy and time should be improved.

Response:

AMI will have little impact on the new Billing Index SQI. The Billing Index is a blend of three components; Accuracy, Completion and Timeliness, which were described in Appendix D6, Section 3.2.3, page 6-7 (Exhibit B-1-1). Accuracy of bills is based on input of data which could see a slight reduction in the error rate, as a small portion of errors are due to human error. However, as the index for this sub-measure is already at 99.9%, we do not believe any change is necessary. The second sub-measure is Timeliness which measures the number of invoices delivered to Canada Post within two days of the date the statement file is created. The third sub-measure Completeness measures the percent of accounts billed within two days of scheduled billing date. AMI may have a small impact on both of these sub-measures due to the reduced number of bills put on hold for review (Accuracy) as noted in the first sub-measure however the reduction is expected to be quite modest so again no measurable impact to either of these two sub-measures. As AMI will have very little impact on each of the sub-measures, the Company believes that the proposed measure will remain appropriate and relevant for the PBR period.

64.1.1 Please explain why this SQI is still relevant.

Response:

Please refer to the response for BCUC IR 1.64.1.

65.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.2.4 Meter Reading Accuracy, p. 7

AMI Impact

65.1 Please explain how AMI will influence this SQI, as accuracy should be improved.

Response:

AMI is expected to positively influence this SQI for the majority of meters included in the AMI RF-mesh, automatically reporting hourly-interval consumption data on a daily basis, thereby eliminating any potential errors arising from a manual meter reading process.

However, as the AMI CPCN noted, there will be some meters that will continue to be read manually on an interval as defined by the applicable tariff. These meters will remain susceptible to the potential errors inherent in the manual meter reading process.

65.1.1 Considering the recently approved AMI project, please explain why this SQI is still relevant.

Response:

Please refer to the response for BCUC IR 1.65.1.

66.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 5 DISCONTINUED SQIs, pp 12-13

Generator Forced Outage Rate

Generator Forced Outage Rate "is indicative of a generator's reliability and is measured as the ratio of forced outages (hours) to total operating time (hours). A Generator Forced Outage means the occurrence of a component failure or other event which requires that the generating unit be removed from service immediately or up to and including the very next weekend."

66.1 As FBC owns four vintage hydro-electric generating plants on the Kootenay River with an installed capacity of 235 MW and is planning capital expenditures to upgrade these plants. Please discuss why the generators' reliability should be excluded from the proposed SQIs.

Response:

Please refer to the response to BCUC IR 1.60.1.2.

66.2 Provide the generator availability factor, forced outage count, forced outage failure, and failure rate by generator for all units grouped by dam for the years 2007 through 2012.

Response:

The generator availability factor, forced outage count, forced outage failure and failure rate are given below:

	2007				2008				2009			
	AF	# of FO	FOR	ICBF	AF	# of FO	FOR	ICBF	AF	# of FO	FOR	ICBF
Lower Bonnington - 01	97.98%	4	0.03%	2.02%	99.09%	5	0.04%	0.91%	99.94%	3	0.00%	0.02%
Lower Bonnington - 02	92.48%	4	0.01%	7.54%	99.39%	1	0.00%	0.61%	99.86%	7	0.08%	0.10%
Lower Bonnington - 03	64.97%	1	0.06%	35.03%	99.10%	0	0.00%	0.90%	99.93%	4	0.07%	0.06%
Upper Bonnington - 01	99.78%	0	0.00%	0.24%	98.81%	0	0.00%	1.19%	97.37%	1	0.08%	2.63%
Upper Bonnington - 02	99.84%	0	0.00%	0.17%	97.78%	0	0.00%	2.26%	97.51%	1	0.17%	2.49%
Upper Bonnington - 03	99.81%	2	0.14%	0.20%	96.60%	1	0.20%	3.40%	90.01%	3	42.58%	9.99%
Upper Bonnington - 04	99.63%	1	1.12%	0.43%	95.61%	2	1.80%	4.39%	97.70%	1	0.21%	2.30%
Upper Bonnington - 05	98.84%	6	0.47%	1.16%	99.28%	6	0.40%	1.50%	97.44%	4	0.00%	3.70%
Upper Bonnington - 06	97.41%	0	0.00%	2.59%	99.30%	3	0.11%	0.68%	97.50%	0	0.00%	2.50%
South Slocan - 01	99.90%	0	0.00%	0.10%	99.10%	1	0.00%	0.90%	59.63%	3	0.00%	40.31%
South Slocan - 02	66.27%	0	0.00%	33.73%	96.87%	3	0.12%	3.13%	88.75%	8	0.09%	11.25%
South Slocan - 03	98.85%	0	0.00%	1.15%	64.68%	0	0.00%	35.49%	78.63%	1	0.00%	21.37%
Corra Linn - 01	98.87%	0	0.00%	1.13%	98.68%	3	0.06%	1.29%	99.78%	2	0.00%	0.22%
Corra Linn - 02	98.72%	1	0.02%	1.28%	98.70%	0	0.00%	1.32%	100.00%	0	0.00%	0.00%
Corra Linn - 03	99.03%	2	0.12%	0.97%	99.10%	2	0.04%	0.90%	99.97%	3	0.07%	0.03%

	2010				2011				2012			
	AF	# of FO	FOR	ICBF	AF	# of FO	FOR	ICBF	AF	# of FO	FOR	ICBF
Lower Bonnington - 01	99.01%	0	0.00%	0.99%	99.12%	0	0.00%	0.88%	96.45%	8	1.56%	3.54%
Lower Bonnington - 02	99.02%	2	0.05%	0.98%	98.64%	2	1.07%	1.36%	97.82%	8	0.08%	1.30%
Lower Bonnington - 03	99.04%	0	0.00%	0.96%	99.10%	1	0.00%	0.90%	98.87%	5	0.05%	1.12%
Upper Bonnington - 01	96.84%	2	2.90%	3.16%	99.04%	0	0.00%	0.96%	97.60%	8	1.57%	1.52%
Upper Bonnington - 02	98.78%	0	0.00%	1.22%	98.80%	0	0.00%	1.20%	90.42%	5	0.23%	9.47%
Upper Bonnington - 03	96.33%	0	0.00%	3.67%	98.83%	0	0.00%	1.17%	91.40%	7	0.24%	7.86%
Upper Bonnington - 04	99.10%	0	0.00%	0.90%	98.82%	4	0.00%	1.18%	96.03%	8	6.56%	3.23%
Upper Bonnington - 05	98.53%	3	0.31%	1.47%	98.78%	0	0.00%	1.22%	97.50%	8	0.40%	2.43%
Upper Bonnington - 06	99.09%	1	0.19%	0.91%	97.18%	0	0.03%	2.82%	98.34%	8	0.58%	1.59%
South Slocan - 01	87.79%	4	0.10%	12.21%	98.99%	0	0.00%	1.01%	98.97%	2	0.02%	1.03%
South Slocan - 02	97.54%	2	0.01%	2.44%	98.80%	0	0.00%	1.20%	98.72%	3	0.03%	1.27%
South Slocan - 03	98.39%	0	0.00%	1.61%	99.11%	2	0.01%	0.89%	98.84%	2	0.00%	1.40%
Corra Linn - 01	60.05%	1	0.00%	39.93%	80.46%	1	0.40%	19.54%	98.53%	1	0.00%	1.47%
Corra Linn - 02	98.83%	6	0.04%	1.09%	47.21%	1	0.01%	52.79%	97.16%	4	0.01%	2.85%
Corra Linn - 03	97.88%	3	0.06%	2.12%	98.72%	0	0.00%	1.28%	83.39%	6	0.16%	16.60%

67.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 5 DISCONTINUED SQIs, pp 12-13

Other Discontinued SQIs

67.1 Since the discontinued SQIs had importance in the previous PBR, please explain in detail why FBC discontinued the following SQIs:

- Residential Connections Completion Time,
- Residential Extensions Quoting Time
- Residential Extensions Completion Time
- Injury Severity Rate (why was the ISR blended into the AIFR?)
- Vehicle Incident Rate

__Response:__

The first three indicators listed above were included in the previous PBR Plan in recognition that the Company's field services responsiveness to routine customer wait times for new connections was in need of improvement at the time. Over the term of the previous PBR period, FBC addressed this area of its customer service and improvement was seen throughout the PBR term such that wait times for new customer connections are at an acceptable level of service.

For the proposed 2014-2018 PBR period, FBC considered a number of criteria in selecting the appropriate SQIs to track. These criteria are set out in Table D6-1 in Appendix D6 of Exhibit B-1. In developing the suite of SQIs for the proposed PBR period, FBC sought not only to select the appropriate measures but also the optimal number of measures (i.e. how many). As indicators are an important communication tool of the overall service level to customers, FBC believes it is most appropriate to focus on a few key SQIs that reflect the overall areas of importance to the Company and its customers.

68.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.3.1 System Reliability Indicators, p. 8

The 2.5 Beta Method for Normalizing Utility Reliability Performance

FBC states "Major event days in the FBC service territory have been caused by mudslides, windstorms and wildfires"

68.1 As Major events are events that are beyond the design and/or operational limits of a utility, please provide the design and/or operational limits of the FBC system for a windstorm.

Response:

The significant capital upgrades completed by FBC over the past 10 years have improved the design resiliency of the system to withstand major events. For example, much of the FBC bulk transmission system is now operated meshed and this reduces the likelihood of wide-scale customer outages due to the loss of a single major transmission line. As a result, the limiting factor to withstand major windstorms is generally crew resource limitations as opposed to design limitations. As a mixed urban/rural utility, FBC's distribution system has a large amount of radial distribution. This configuration constrains the ability of the Company to restore service by rerouting around faults. Instead, the faulted sections must be repaired to restore service to the downstream customers. During major windstorms, the sheer number of individual outage locations overwhelms the ability of FBC to respond with either in-house or contractor crews. It is not possible to quantitatively provide these limitations as it depends on the number, location and nature of the outages. Proactively staffing for these very infrequent events would have a negative impact on customer rates as there would be insufficient work to employ these crews for the vast majority of the time. Designing around these radial circuit limitations would also have a very significant rate impact; this is due to the large amount of distribution infrastructure that would need to be constructed to provide customers with alternate distribution supply sources.

68.2 Please discuss how other jurisdictions in Canada determine that a major event has occurred.

Response:

The Alberta Utilities Commission, like FBC, employs the use of the IEEE 2.5 Beta Method for normalizing reliability performance. However, other jurisdictions, such as Maritime Electric serving Prince Edward Island defines a major event as an event that impacts 10 percent of its customers for more than 10 minutes.

The Ontario Energy Board (OEB) recently amended the reporting requirement for the reliability data of Ontario utilities to no longer require normalization of reliability data. Instead, the OEB requires utilities to report the details on the cause of interruptions, and therefore is not recommending any methodology for the reporting of normalized data.

68.3 Does the Ontario Energy Board (OEB) accept the IEEE 2.5 Beta Method for Normalizing Utility Reliability Performance methodology for normalizing data?

Response:

Please refer to the response to BCUC IR 1.68.2.

A Major Event Day (MED) is any day that exceeds a daily SAIDI threshold called TMED. Daily SAIDI values for the past five years are used to calculate TMED.

68.4 Please provide the TMED for each of the past five years.

Response:

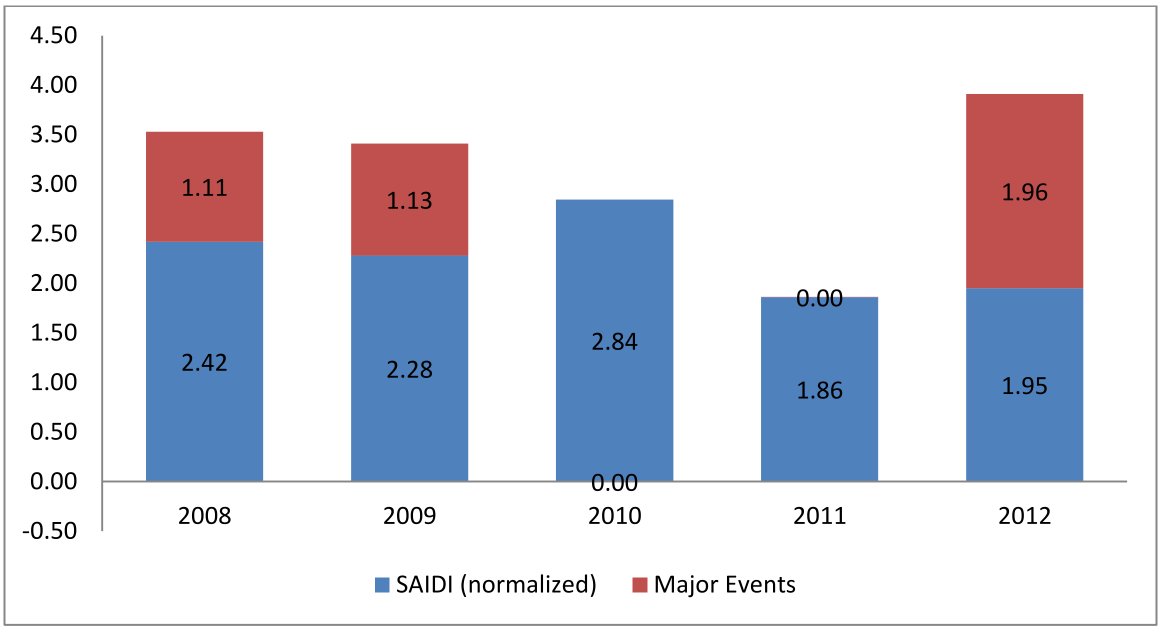
Please refer to the below table for the T_{MED} for each of the past five years in minutes and hours.

	T_{MED} (min)	T_{MED} (hrs)
2008 Threshold	18.1	0.302
2009 Threshold	18.0	0.301
2010 Threshold	16.1	0.269
2011 Threshold	17.6	0.293
2012 Threshold	15.9	0.266

68.5 For each of the past five years, please provide a stacked bar graph showing the adjusted vs. the unadjusted SAIDI values for Major Events in the FBC service area.

Response:

Please refer to the below figure showing normalized SAIDI and major events for each of the past five years.



68.6 Please discuss when and how FBC determines an outage is reportable to the BCUC.

Response:

In general, FBC only reports outages to the BCUC through its SAIDI and SAIFI metrics. Individual outage events are not reported unless they are extreme and affect a very large number of customers. FBC is unaware of any recent reports of this nature.

68.7 Please explain the impact on CAIDI when FBC normalizes SAIDI and SAIFI.

Response:

CAIDI is defined as SAIDI divided by SAIFI. When the SAIDI and SAIFI figures are both normalized, the overall ratio (and hence CAIDI) generally decreases since the long-duration outages due to major events are excluded.

68.8 FBC states "FBC proposes to include this metric as an informational service quality indicator with no benchmark as the results are to be considered informational in nature" (Exhibit B-1-1, Appendix D6, p. 2)

68.9 Please provide reasons why FBC considers these metrics (SAIDI & SAIFI) to be an informational service quality indicator with no benchmark impact as they relate directly to system reliability performance that relate to capital and operating and maintenance expenditures.

Response:

FBC considers the results for the SAIDI & SAIFI metrics to be informational in nature as there may be external factors that can influence the results. Due to events beyond the Company's control, such as local and severe weather conditions and third party damage, there may be considerable annual variation in the results, making the task of setting an appropriate benchmark challenging. Benchmarks developed in the past were adjusted for anticipated impacts of forecast events such as the impact of capital programs being implemented.

Instead, recognizing the importance of the need to measure transmission and distribution system reliability, FBC proposes to continue to report SAIDI and SAIFI results to monitor for any significant negative trends in system reliability.

69.0 Reference: Exhibit B-1-1, Tab D, Appendix D6 – Service Quality Indicator Report,

Section 3.3.2 All Injury Frequency Rate, p. 9

Lost Time Injuries (LTI)and Medical Treatment Injuries (MT) Indicators,

69.1 Please explain why LTI and MT are not reported separately.

Response:

This FBC reporting practice is aligned with that of other industry comparator groups across Canada. Lost Time Injuries (LTI) and Medical Treatment Injuries (MT) are reported as one category of injuries to be consistent with this standardized approach.

69.2 Please explain why the All Injury Frequency Rate (AIFR) is calculated using the simple sum of LTI plus MT instead of weighting the LTI more since it represents incidents that are more serious.

Response:

The All Injury Frequency Rate (AIFR) is a comprehensive, industry accepted metric that defines the frequency of injury occurrence and that has been utilized by safety professionals for decades; the AIFR metric is also recognized by the provincial health and safety regulator, WorkSafeBC. The AIFR is calculated using the total number of "recordable injuries" multiplied by 200 thousand, divided by total hours worked. The lower the AIFR, the lower the overall risk of injury or illness.

69.3 Please provide a list of other jurisdictions that use the AIFR methodology that FBC is proposing.

Response:

The All Injury Frequency Rate (AIFR) methodology is utilized by organizations across Canada and North America, and more specifically, by Fortis operating group companies and peer-utility members of the Canadian Electrical Association (CEA), as a comparator with respect to safety performance.

70.0 Reference: Orders G-58-06 and G-193-08

Historical SQIs

70.1 Please complete the actual 2007-2012 data and forecasted 2013 data for the following table:

	System Average Interruption Duration Index	System Average Interruption Frequency Index	Generator Forced Outage Rate	All Injury Frequency Rate	Injury Severity Rate	Vehicle Incident Rate	Billing Accuracy – percentage of bills rejected by system	Meters Read as Scheduled	Contact Center – percentage of calls answered within 30 seconds	Emergency Response Time – percentage of calls responded to within 2 hours	Residential Service Connections – percentage connected within 6 working days	Residential Extensions – percentage quoted within 35 working days	Residential Extensions – percentage connected within 30 working days	Directional Metric – Customer Satisfaction Survey
Year	Reliability			Safety & Health			Customer Service							
2007														
2008														
2009														
2010														
2011														
2012														
2013														

Response:

Please refer to the below table which sets out the calendar year results of each historical performance standard back to 2007. Note that the results provided for 2013 are year to date as of July 31, 2013.

	System Average Interruption Duration Index	System Average Interruption Frequency Index	Generator Forced Outage Rate	All Injury Frequency Rate	Injury Severity Rate	Vehicle Incident Rate	Billing Accuracy – percentage of bills rejected by system	Meters Read as Scheduled	Contact Center – percentage of calls answered within 30 seconds	Emergency Response Time – percentage of calls responded to within 2 hours	Residential Service Connections – percentage connected within 6 working days	Residential Extensions – percentage quoted within 35 working days	Residential Extensions – percentage connected within 30 working days	Directional Metric – Customer Satisfaction Survey
Year	Reliability			Safety & Health			Customer Service							
2007	2.51	2.00	0.08%	1.71	11.83	1.73	0.044%	98%	70%	92%	87%	92%	89%	8.6
2008	2.42	2.14	0.11%	2.87	23.37	0.94	0.047%	98%	70%	94%	91%	94%	96%	8.6
2009	2.28	1.48	0.90%	1.41	23.43	2.20	0.044%	98%	70%	92%	90%	96%	94%	8.6
2010	2.84	2.27	0.10%	1.72	5.82	0.20	0.050%	98%	70%	93%	96%	99%	98%	8.8
2011	1.86	1.38	0.09%	1.48	17.77	1.21	0.040%	98%	70%	92%	93%	97%	94%	8.7
2012	1.95	1.26	0.52%	1.72	13.57	0.44	0.032%	98%	70%	91%	92%	97%	96%	8.4
2013	2.09	1.66	0.85%	3.80	21.76	0.44	0.032%	65%	70%	94%	91%	96%	94%	8.1

70.2 Please provide the new forecasted targets for the new reduced set SQIs for the PBR term 2014-2018.

Response:

FBC has proposed the following benchmarks for the proposed SQIs for the 2014-2018 PBR Term.

Proposed Performance Measures for 2014-2018 PBR Term	Proposed Benchmark for 2014-2018 PBR Term
Emergency Response Time	85%
Telephone Service Factor	70%
First Contact Resolution	78%
Billing Index	5
Meter Reading Accuracy	97%
System Average Interruption Duration Index (SAIDI)	Informational Indicator
System Average Interruption Frequency Index (SAIFI)	Informational Indicator

Proposed Performance Measures for 2014-2018 PBR Term	Proposed Benchmark for 2014-2018 PBR Term
All Injury Frequency Rate	Informational Indicator
Customer Satisfaction Index (CSI)	Informational Indicator

D. PBR FORECAST – LOAD FORECAST

71.0 Reference: Exhibit B-1, pp. 77-90

2014-2018 Load Forecast

71.1 Please also provide the underlying data for Figure C1-2 in tabular form.

Response:

The underlying data for Figure C-2 is provided below.

Year	Residential	Commercial	Wholesale	Industrial	Lighting	Irrigation	Loss
2011	36.2%	19.1%	26.4%	7.9%	0.4%	1.2%	8.9%
2012	35.9%	19.9%	26.3%	8.5%	0.4%	1.1%	7.9%
2013	38.9%	22.1%	19.4%	10.1%	0.4%	1.2%	8.0%
2014	39.9%	23.1%	16.5%	11.1%	0.4%	1.2%	7.9%
2015	39.7%	23.3%	16.5%	11.0%	0.4%	1.2%	7.9%
2016	39.6%	23.5%	16.5%	11.0%	0.4%	1.2%	7.8%
2017	39.7%	23.7%	16.5%	10.9%	0.4%	1.2%	7.8%
2018	39.6%	23.9%	16.5%	10.8%	0.4%	1.1%	7.7%

71.2 For Figure C1-3, C1-6 to C1-12, please explain why the energy consumption values for the years 2008 to 2012 are reported to be "before savings" instead of "after savings". In particular, for Figures C1-7, C1-8, C1-10 and C1-11 where the Figures report the "actual energy consumption" for the years 2008-2012, why would the actual energy use not include the Demand Side Management (DSM) savings?

Response:

"Before savings" here means before *incremental* savings, which are DSM and other savings introduced from 2013 onwards.

From Figure C1-3, the savings for the years 2013 to 2018 can be calculated by subtracting the "after savings" values from the "before savings" values to obtain the following:

	2013	2014	2015	2016	2017	2018
Savings	24	51	70	88	103	119

71.3 Please reconcile these numbers with the DSM and Other Savings for 2013-2018 found in Figure C1-4 and explain the differences.

Response:

The numbers obtained above are the gross load reductions, which include savings with losses at the gross loss rate of 8.0% or the net loss rate of approximately 8.7%, and the loss reduction due to AMI projects. On the other hand, the numbers in Figure C1-4 are the net savings (without losses) only. As shown below, adding losses to the net saving numbers and then adjusting for AMI-based loss reduction yield the same results as in the table above (with small differences due to rounding).

Energy (GWh)	2013	2014	2015	2016	2017	2018
Net Saving in Figure C1-4 (a)	21	44	60	75	86	100
Gross Saving with Losses (b =1.087*a)	22	48	65	81	94	109
Further AMI Loss Reduction (c)	1	3	4	6	7	9
Total Gross Load Reduction (d=b+c)	24	51	69	87	101	118

72.0 Reference: Exhibit B-1, p. 94

Table C1-3, Actual and Forecast Year-End Customer Count

72.1 Please provide the method used by FBC to forecast the year-end commercial customer count? Provide all the necessary assumptions and results.

<u>Response:</u>

FBC forecast the total year-end commercial customer count as the sum of (1) the commercial count excluding CoK and (2) the CoK commercial count.

(1) The year-end commercial count without CoK was forecast based on an OLS regression on the provincial GDP over the 1990-2012 period, adjusted for the Princeton Light and Power integration in 2007 as follows:

$Count_t = b_0 + b_1*GDP_t + b_2*Princeton\ Event_t$

Note that these independent variables were also used to forecast the commercial load. The regression results are provided below.

Number of Data	23	p-value
Intercept b_0	2,671	0.00
GDP b_1	0.057	0.00
Princeton Event b_2	-635	0.00
Adjusted R-sq	0.99	
F statistic		0.00
Durbin-Watson	1.12	Inconclusive

(2) After the load reclassification in April 2013, the year-end commercial count for CoK was forecast at an assumed constant growth based on the 5-year average growth in the 2008-2012.

The results are as follows.

	2013	2014	2015	2016	2017	2018
FBC w/o CoK	12,017	12,262	12,516	12,758	12,953	13,243
CoK	1,572	1,585	1,598	1,610	1,623	1,636
FBC with CoK	13,589	13,847	14,114	14,368	14,576	14,879

73.0 Reference: Exhibit B-1, p. 81; Exhibit B-1-1, Appendix E2, pp. 22-23 &25-26; FBC's 2012-2013 Revenue Requirements and Review of 2012 Integrated Resource Plan – Load Forecast Technical Committee Report, pp. 2-3

FortisBC's Commitments for the 2014 Load Forecast

In Section 3 (DSM and Other Savings Forecasts) of the LFTC Report (p. 4), FBC stated "[g]iven the complexity of this issue it is difficult to ensure that the Company's methodology eliminates all potential for double-counting of DSM related savings. The Company will continue to investigate this issue for improvement. Additional study must also be given to the effect on the load forecast of codes and standards, natural conservation and free ridership. These will be reviewed by the Company as part of the 2014 load forecast".

73.1 Please discuss the results of the Company's investigation in relation to the potential for DSM double-counting, the effect on the load forecast of codes and standards, natural conservation and free ridership.

Response:

The Company's investigation into the issue of double counting included reviewing the two main components of the load forecast model separately, namely the before DSM forecast and the DSM forecast. The before DSM forecast is based on a set of quantitative methodologies which incorporate historical data. In the context of double counting, the effect of DSM programs and the level of natural conservation and free ridership are all embedded in the historical data. Thus, the before DSM forecast includes the impact of these factors. This is the expected forecast assuming no new DSM programs and no significant changes in the other factors such as free ridership.

The DSM forecast is conducted by the DSM group as a separate process where the incremental savings from DSM programs are estimated.

The after DSM forecast is then subtracted from the before DSM forecast. The Company believes that having two clearly defined processes and the way the after DSM forecast is produced ensure that there is no overlap of savings that potentially lead to double counting issues.

In addition, the Company conducted a comparison of the BC Hydro end-use driven forecasting methodology, where codes and standards overlap with DSM as documented in their Integrated Resource Plan Appendix 2A. Consequently, their DSM estimates were discounted to address this issue. Since FBC uses a different forecast methodology, and its DSM plan excludes codes and standards, its forecasts are not subject to this double-counting issue.

The Company's comparison study concluded that this type of double counting arose from the end use methodology and that given the Company's current forecast methodologies and the treatment of DSM, the same type of double counting issues are not present here.

In Section 8 (Price Elasticity and Rate Structures) of the LFTC Report (p. 7), FBC stated "[t]he Company explained that it did not use price elasticity in its forecast but that the price elasticity is implicitly embedded in the UPC, to the extent that future rate increases are similar in scale to previous rate increases. If the rate of change differs in the forecast period, then an explicit recognition of price elasticity would be required. The Company committed to investigate the issue of price elasticity further and to incorporate any appropriate findings into the next load forecast."

On page 81 of Exhibit B-1 in FBC's 2014-2018 PBR & RRA, FBC states "[r]ate-driven savings due to price elasticity are also taken into account and deducted from the before-saving loads. This is independent of the RCR mentioned above and applied to all rate classes. In the absence of specific information with regards to price elasticity, FBC has applied the assumption of -0.05 elasticity made by BC Hydro, which is considered to be reasonable given its geographic proximity and similarities in terms of customer mix and behaviours."

73.2 Please confirm that FBC started to recognize explicitly in its load forecast for the 2014-2018 PBR & RRA rate-driven savings due to price elasticity and that this in effect constitutes a change in methodology from previous filings. If not confirmed, please reconcile the two statements.

Response:

FBC confirms that it started to recognize rate driven savings due to price elasticity in its load forecast. FBC sees this as a slight adjustment in its forecast and not a change in methodology.

73.3 If confirmed, please provide a side-by-side comparison of the previous versus new methodology and a detailed explanation to support the new methodology presented, in accordance with Commitment # 8 of the LFTC Report.

Response:

Rate-driven savings is a rate-induced saving in addition to the rate-structure saving RCR already introduced in the 2012-2013 RR as listed below.

	Rate-sensitive Savings	
Application	Residential Conservation Rate (RCR)	Rate-driven Savings due to Price Elasticity
2012-2013 RRA	Yes	No
2014-2018 PBR RRA	Yes	Yes

The forecast annual rate-driven savings (in GWh) in 2014-2018 are given below.

2014	2015	2016	2017	2018
9.7	9.8	9.9	10.0	10.1

In the utility practice, it is believed that electricity savings induced by price elasticity can be from natural conservation (as if there was a single rate level) and incremental conservation (due to rate structures that apply different rates to different consumption levels). Utilities such as BC Hydro may address these savings separately[15]. Although there was no statistically significant downward trend for the residential UPC, FBC considered the potential impacts of rate-driven savings in its service area as a result of evidence of declining UPC in the past three years (below).

Residential UPC (MWh)

2009	2010	2011	2012
12.90	12.77	12.70	12.41

Since this subject is relatively new to the Company, FBC decided to make use of BC Hydro's approach as much as possible, given the closeness of the two utilities and the fact that this approach has been verified during the filing process of BC Hydro's 2008 LTAP.

The response to BCUC IR 1.73.2 already shows fluctuating rate increases in the FBC service area, which may not have given customers a clear signal to respond to the rate changes and save energy. With much more stabilized rate increase proposed in the 2014-2018 PBR, FBC expects to see more price responses from customers.

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[15] Exceprt from BC Hydro's 2012 IRP draft, Appendix A, p. 19:
"Conservation induced by average rate increases (including rate riders) is referred to as "natural conservation" whereas incremental conservation induced by annual rate structure changes is known as "rate structure conservation". The sum of the two is counted as total conservation. In BC Hydro's load forecast, "natural conservation" is included in the before-DSM load forecast, and "rate structure conservation" is included in the estimate of DSM savings."

73.3.1 Please discuss whether the change in methodology was due to the fact that the rate increases in the forecast period differ from those in previous years so as not to be already captured in the UPC, as noted in the LFTC Report, or to other reasons.

Response:

Please refer to the response to BCUC IR 1.73.3.

73.3.2 Please provide FBC's annual rate increases in the last 10 years compared to the rate increases in the next 5 years.

Response:

Please refer to the below table.

Annual Rate Change	Percent Increase (Reduction)	Order(s)
January 1, 2003	4.3%	G-10-03
January 1, 2004[1]	0.4%	G-38-04 & G-82-04
January 1, 2005	3.4%	G-52-05
January 1, 2006	5.9%	G-58-06
January 1, 2007[2]	2.8%	G-162-06 & G-20-07
January 1, 2008[3]	3.4%	G-147-07 & G-70-08
January 1, 2009[3]	5.3%	G-193-08
January 1, 2010[3]	7.1%	G-162-09 & G-127-10
January 1, 2011[3]	7.5%	G-184-10, G-195-10 & G-191-11
January 1, 2012	1.5%	G-110-12
January 1, 2013	4.2%	G-110-12
January 1, 2014	3.3%	
January 1, 2015	3.3%	
January 1, 2016	3.3%	

Annual Rate Change	Percent Increase (Reduction)	Order(s)
January 1, 2017	3.3%	
January 1, 2018	3.3%	

Notes:

[1] The annual general rate increase occurred on May 1, 2004, however for comparison purposes the full year equivalent of the mid-year 2004 rate increase has been provided. As well, a mid-year rate decrease also occurred in 2004. The full year equivalent of the mid-year 2004 rate decrease has been added to the annual general rate increase.

[2] A mid-year rate increase occurred on April 2, 2007. The full year equivalent of the mid-year 2007 rate increase has been added to the annual rate increase that occurred on January 1, 2007.

[3] In each of the years of 2008 through 2011, FBC flowed through increased power purchase costs as a result BC Hydro rate increases mid-year. The full year equivalent of the mid-year rate increases has been added to the annual rate increase that occurred at the beginning of each year.

73.4 Please confirm that what FBC means by “an assumption of -0.05 elasticity” is that for each 1 percent increase in the price of electricity, the energy use decreases by 0.05 percent.

Response:

Confirmed.

74.0 Reference: Exhibit B-1-1, Appendix E2, p.7

Weather Normalization

FBC states "[t]he Company also investigated possible global warming effects through a long-term (30-year) trend analysis of HDD and CDD, but no statistically significant trend of increasing temperature was found for any month except for July as summarized below. Therefore, this load forecast does not explicitly address global warming effects. This is in line with the current utility practice according to surveys."

Table E2-2: Statistical Significance of Trend Analysis on HDD and CDD over 1983-2012

p-value	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
HDD	0.770	0.730	0.878	0.421	0.733				0.019	0.116	0.577	0.069
CDD						0.731	0.023	0.052				

74.1 Please discuss in greater detail the trend analysis undertaken by FBC to investigate possible global warming effect.

<u>Response:</u>

The Company applied a simple trend analysis for each month with HDD and CDD data over the last 30 years to evaluate the global warming effect, or rather any effect positive or negative on the climate. The HDD and CDD data are provided in the tables below. The p-values reported are the ones associated with the F test, with the significance level chosen at 0.05. For any insignificant result (with p-value greater than 0.05) for a month, it was concluded that there was no global warming effect for that month.

HDD

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1983	508	398	365	283	128	56	37	4	146	287	368	736
1984	569	465	383	308	225	80	13	17	173	360	447	742
1985	674	561	473	291	135	46	0	23	177	321	702	698
1986	565	536	366	311	174	25	32	0	146	301	454	568
1987	577	440	376	226	124	29	10	14	70	284	384	570
1988	618	486	404	237	147	58	13	16	121	251	419	590
1989	586	657	447	240	151	24	14	22	84	287	407	515
1990	529	538	416	239	165	69	7	12	48	302	411	714
1991	698	386	438	270	163	72	3	13	52	309	428	509
1992	486	417	351	251	100	14	6	16	139	251	436	693
1993	722	562	434	284	76	54	22	23	109	256	532	529
1994	480	515	391	216	106	59	6	8	40	280	505	548
1995	574	428	438	275	93	32	4	43	59	284	416	557
1996	675	559	455	263	207	50	14	15	149	321	522	697
1997	604	513	414	299	110	54	12	10	82	284	421	524
1998	584	412	394	259	77	23	0	6	49	283	358	555
1999	506	427	418	292	212	73	20	10	110	308	374	493
2000	583	491	394	250	167	59	15	24	116	298	488	628
2001	552	513	409	289	133	67	10	2	63	319	374	520
2002	528	455	502	271	166	32	12	20	85	331	400	479
2003	487	455	388	259	149	22	1	1	68	219	520	554
2004	621	501	352	219	130	31	2	4	105	267	423	504
2005	636	490	371	243	86	56	2	4	102	257	463	602
2006	450	495	417	252	144	25	3	7	76	274	461	585
2007	625	448	363	277	107	47	2	13	111	300	461	561
2008	639	483	432	341	112	63	4	16	118	291	404	700
2009	640	524	472	309	136	11	1	12	55	316	391	658
2010	508	399	363	255	177	50	13	17	92	229	497	550
2011	549	528	400	324	166	52	10	1	53	273	463	555
2012	612	506	418	274	163	81	9	7	63	271	399	525

CDD

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1983	0	0	0	0	19	15	24	84	2	0	0	0
1984	0	0	0	0	0	15	89	75	1	1	0	0
1985	0	0	0	0	7	25	153	41	1	0	0	0
1986	0	0	0	0	23	45	26	98	9	0	0	0
1987	0	0	0	0	6	63	77	45	18	0	0	0
1988	0	0	0	0	1	34	75	51	15	0	0	0
1989	0	0	0	0	2	40	83	47	1	0	0	0
1990	0	0	0	0	0	25	110	103	4	0	0	0
1991	0	0	0	0	0	7	88	116	4	0	0	0
1992	0	0	0	0	15	98	84	99	4	0	0	0
1993	0	0	0	0	29	18	19	53	15	0	0	0
1994	0	0	0	0	2	19	163	81	6	0	0	0
1995	0	0	0	0	15	39	92	28	22	0	0	0
1996	0	0	0	0	0	6	116	71	1	0	0	0
1997	0	0	0	0	8	14	48	87	7	0	0	0
1998	0	0	0	0	2	22	175	131	47	0	0	0
1999	0	0	0	0	2	22	55	111	0	0	0	0
2000	0	0	0	0	1	24	83	83	1	0	0	0
2001	0	0	0	0	19	12	102	94	7	0	0	0
2002	0	0	0	0	2	61	129	81	6	0	0	0
2003	0	0	0	0	5	53	166	118	27	0	0	0
2004	0	0	0	0	0	64	136	118	1	0	0	0
2005	0	0	0	0	12	14	92	101	5	0	0	0
2006	0	0	0	0	14	44	144	68	10	0	0	0
2007	0	0	0	0	5	30	154	58	8	0	0	0
2008	0	0	0	0	10	28	110	79	2	0	0	0
2009	0	0	0	0	13	48	157	112	20	0	0	0
2010	0	0	0	0	0	20	118	84	3	0	0	0
2011	0	0	0	0	0	9	60	95	28	0	0	0
2012	0	0	0	0	0	9	121	106	6	0	0	0

74.2 Please explain how to interpret the data in Table E2-2. In particular, which statistic is being used to test for a statistically significant trend and what are the threshold values to determine the existence of a statistically significant trend?

Response:

Please refer to the response to BCUC IR 1.74.1.

75.0 Reference: Exhibit B-1-1, Appendix E2, p. 10 and 14

Durbin-Watson Statistic

FBC notes that the Durbin-Watson test was “passed” in the case of the two OLS regressions for residential customer counts (Table E2-4 on page 10) and commercial load (Table E2-8 on page 14).

75.1 In each case, please provide the lower and upper critical values to which the Durbin-Watson statistic is compared and also provide the significance level used.

Response:

Please find the information below. Please note that if both the Durbin-Watson statistic and the value (4-DW are both greater than the upper bound, then the test passes.

OLS Regression	DW Statistic	Lower Bound	Upper Bound	Significance Level
Residential Customer Count	1.52	0.61	1.40	0.05
Commercial Load	1.80	0.81	1.56	0.05

75.2 Please confirm that what FBC means by “passed” is that there is no autocorrelation of the residuals in the OLS regression and therefore, the statistical significance of the estimated parameters in the OLS regression will not be affected.

Response:

Confirmed.

76.0 Reference: Exhibit B-1-1, Appendix E2, p.11

Energy Forecast – Residential

FBC states "[t]here was a need to revise the method to forecast the residential customer count as the former method significantly overforecast in years 2011-2012 (by 662 and 2,092 customers respectively)."

Table E2-5: Comparisons of Forecasting Methods for the Residential Customer Count without CoK

Year	Actual Year-end Customer Count	Regression on the Provincial Housing Starts	Regression on the FBC Population	Regression on the Provincial Housing Starts	Regression on the FBC Population
2007	93,647	91,389	93,233	(2,258)	(414)
2008	95,502	95,581	96,200	79	698
2009	96,565	96,410	97,356	(155)	791
2010	97,883	98,058	97,585	175	(298)
2011	98,795	99,309	98,216	514	(579)
2012	99,228	100,394	99,030	1,166	(198)
Mean Absolute Deviation (2011-2012)				840	389
Forecast				**Growth**	
2013		100,753	99,768	1,525	540
2014		102,331	100,487	1,579	719
2015		104,076	101,288	1,744	801
2016		105,906	102,142	1,830	854
2017		107,724	103,044	1,819	902
2018		109,550	103,966	1,826	921

76.1 Please confirm that the former method overforecast by 514 and 1,166 customers in years 2011 and 2012 respectively (as shown in Table E2-5), and not 662 and 2,092 as indicated in the quote above.

Response:

Not confirmed. The overforecasting of customer counts of 514 and 1,166 for 2011 and 2012 respectively was the result of updating the former method in the 2012-2013 RR with the data up to 2012. This data update was done to permit a fairer comparison with the new method in the 2014-2018 PBR, which also used data up to 2012. If the data from the 2012-2013 were used (just up to 2010) for the former method, we would have the same model as in the 2012-2013 RR and then end up with the actual overforecasting errors of 662 and 2,092.

FBC also states "[n]ot only does the new method outperform on the 2011-2012 counts…"

76.2 Please explain what criteria were used to determine that the new method outperform on the 2011-2012 counts. In particular, how can a method which forecasts 579 less customers than actual be said to perform better than one that forecasts 514 more customers?

Response:

A forecasting method can underforecast in one year and overforecast in another. Therefore, for validation purposes, unless there is a consistent pattern of underforecasting or overforecasting over a long period, the sign of the forecasting error is typically not of interest, but the absolute error magnitude is. While the old method of regression on the housing starts did better than the new method of regression on the FBC population in 2011, its average performance is worse in the validation period 2007-2012 with the average absolute error of 724 compared to 496 by the new method. Validation results in the most recent years 2011-2012 gave the same conclusion.

76.3 Given that the new forecasting method projects a much slower growth in the number of residential customers than the previous method, please discuss the impacts on the forecast rate increases for 2014-2018 of changing the forecasting method?

Response:

The forecasting method projects slower growth in the number of residential customers than the previous method which results in a cumulative Rate impact of **1.4%** during the period 2014-2018 as indicated in the Table below, and as such is sound and reasonable. Please also see Exhibit B1-1 Appendix E2 and BCUC IR 1.76.1.

Load / Sales / Power Purchase / Customers & Rate Impacts	2014	2015	2016	2017	2018
RRA as Filed					
Gross Load (GWh)	3,519	3,537	3,554	3,572	3,596
Sales Load (GWh)	3,240	3,258	3,276	3,295	3,318
Power Purchase Cost ($000s)	87,814	116,380	134,204	136,716	140,322
Year End Customers (Nos.)	130,323	131,521	132,763	134,007	135,366
Rate Impacts (%)	3.3%	3.3%	3.3%	3.3%	3.3%
Cumulative Rate Impacts (%)	3.3%	6.7%	10.2%	13.9%	**17.6%**
BCUC IR-1 Q76.3					
Gross Load (GWh)	3,538	3,568	3,599	3,630	3,666
Sales Load (GWh)	3,258	3,287	3,317	3,347	3,382
Power Purchase Cost ($000s)	88,791	117,715	136,187	139,332	143,602
Year End Customers (Nos.)	132,168	134,309	136,526	138,686	140,951
Rate Impacts (%)	3.0%	3.0%	3.1%	3.1%	3.1%
Cumulative Rate Impacts (%)	3.0%	6.1%	9.4%	12.8%	**16.3%**
Variance					
Gross Load (GWh)	(19)	(32)	(45)	(58)	(70)
Sales Load (GWh)	(18)	(29)	(41)	(52)	(63)
Power Purchase Cost ($000s)	(977)	(1,335)	(1,983)	(2,616)	(3,280)
Year End Customers (Nos.)	(1,845)	(2,788)	(3,764)	(4,680)	(5,585)
Rate Impacts (%)	0.3%	0.3%	0.2%	0.2%	0.2%
Cumulative Rate Impacts (%)	0.3%	0.6%	0.9%	1.1%	**1.4%**

77.0 Reference: Exhibit B-1, p. 81; Exhibit B-1-1, Appendix E2, pp. 9 & 16

Energy Forecast - Wholesale

FBC states "[t]he integration of COK into FBC direct service effective March 31, 2014 resolved this problem…"

77.1 Please confirm that FBC meant "effective March 31, 2013," as indicated on page 81 of Exhibit B-1 and also on page 9 of Exhibit B-1-1, Appendix E2 instead of "effective March 31, 2014."

Response:

Confirmed. FBC acquired the assets of the City of Kelowna effective March 31, 2013.

78.0 Reference: Exhibit B-1, pp. 88-89; Exhibit B-1-1, Appendix E2, pp. 19-20; FBC's 2012-2013 Revenue Requirements and Review of 2012 Integrated Resource Plan – Load Forecast Technical Committee Report, p. 11

Energy Forecast - Irrigation

In Section 16 (Irrigation Forecast) of the LFTC Report (p. 11), FBC stated that "[s]ix load drivers were looked at but none of them gave any statistically significant results. Additional drivers of CDD and precipitation were also examined for this class but did not give any better results than using the simple average of the five preceding years…However, <u>precipitation in particular required closer examination in future forecasts.</u>" (Emphasis added)

78.1 Please provide the result of the test used to determine that precipitation was not a significant driver of the irrigation load.

<u>**Response:**</u>

The test results to determine that precipitation was not a significant driver of the irrigation load are given below. The table shows the statistical significance (p-value) of the regression of the irrigation load on precipitation for each month, as well as for each season and the irrigation rate period (April-October) using the 2003-2012 data. When the p-value is greater than 0.05, we cannot use precipitation as a predictor for the load.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
p-value	0.87	0.43	0.06	0.34	0.45	0.60	0.38	0.19	0.93	0.85	0.16	0.37

	Spring	Summer	Fall	Winter	Irrigation (Apr-Oct)
p-value	0.904	0.961	0.955	0.375	0.914

79.0 Reference: Exhibit B-1, p. 3; Exhibit B-1-1, Appendix E2, pp. 2-5 & 22-23

DSM and Other Savings

In Table E2-17 on page 22, FBC provides DSM savings by load class for the current FBC system with the CITY OF KELOWNA integration.

79.1 Please explain how the DSM values by load class presented in Table E2-17 are reflected in Tables 1.3 to 1.8 on pages 2-5.

Response:

For each load class, its DSM saving value in each year in Table E2-17 is one of the saving components for the load class. The class' total saving is the difference between the first table "Before-saving" and the third table "After-saving" in Tables 1.3 – 1.8. Note that while DSM and rate-driven savings are common for all load classes, the RCR, CIP, and AMI savings are forecast only for the Residential class.

FBC states that "[t]he rate driven impact of 0.3 percent is the product of the assumed elasticity of -0.05 and the forecast average rate increase of 5.9 percent in 2014-2018. This saving is independent of the RCR saving and applied to all rate classes."

On page 3 of Exhibit B-1, FBC states that "[t]he mechanism not only mitigates rate variability, averaging 3.3 percent annually based on current forecasts of revenue requirements over the PBR Period…"

79.2 Please confirm that the forecast average rate increase requested in this Application is 3.3 percent annually in the period 2014-2018 and not 5.9 percent.

Response:

Confirmed.

79.2.1 If so, please also confirm that the rate-driven impact should have been 0.165 percent instead of 0.3 percent (calculated as the product of the assumed price elasticity of -0.05 and the forecast average rate increase of 3.3 percent).

Response:

Rate-driven saving in this application was assumed to be based on certain percentage of the before-saving load. Therefore its calculation uses an estimated rate increase in the absence of all savings, including DSM and others. The estimate in this application is 5.9%. Meanwhile, the rate increase of 3.3% as mentioned on page 3, Exhibit B-1, is the calculated rate increase in the presence of all savings. As a result, with the assumed price elasticity of -0.05, the rate-driven saving is 0.295%, not 0.165%.

Calculating rate-driven savings using the before-saving load and rate increase has two major advantages. First, this is consistent with the assumption made for the RCR and CIP savings. Second, it simplifies the rate impact calculation process by avoiding the looping issue when using the after-saving information. Given the relatively small contribution of the rate-driven saving to the gross load (less than 0.3%), the Company believes this approach is reasonable.

79.2.2 If so, please provide revised tables whenever rate-driven impacts are included in a table.

Response:

Please refer to the response to BCUC IR 1.79.2.1.

In Table E2-19 and E2-20, FBC provides the RCR and Customer Information Portal (CIP) impacts in percentage and gigawatt hours (GWh) respectively.

79.3 Please explain how the annual savings in percentage and GWh due to the RCR and the CIP respectively were derived. Please clearly explain the assumptions used by FBC to derive these calculations.

Response:

The RCR savings were assumed to increase steadily from 2014 to 2019, eventually reaching 1.9% of residential consumption. This assumption was included as part of the Residential Inclining Block application.

The CIP savings were derived from the BC Hydro estimate in their Smart Metering & Infrastructure Business Case, filed in the AMI proceeding as Exhibit B-1, Appendix C-4, p31. Base assumptions are:

- Customer use of the CIP is assumed at 15%.
- Savings from the CIP are assumed to be 2%.

	2013	2014	2015	2016	2017	2018
RIB (as % of Before-saving Residential Load)	0.00%	0.22%	0.60%	0.98%	1.36%	1.74%
Before-saving Residential Load, incl. CoK (GWh)	1,364	1,416	1,427	1,438	1,450	1,462
RIB (GWh)	0.0	3.1	8.6	14.1	19.7	25.5

	2013	2014	2015	2016	2017	2018
CIP (as % of Before-saving Residential Load)	0.00%	0.00%	0.15%	0.30%	0.30%	0.30%
Before-saving Residential Load, incl. CoK (GWh)	1,364	1,416	1,427	1,438	1,450	1,462
CIP (GWh)	0.0	0.0	2.1	4.3	4.3	4.4

% figures from Table E2-19, p. 23, Section 3, Appendix E2. GWh figures from Table E2-20, p. 23, Section 3, Appendix E2.

79.4 Please confirm that in Tables E2-19 and E2-20, the RCR and CIP values are related to the residential class only whereas the rate-driven impacts in those tables are for all the load classes combined. If not, please clarify.

Response:

Confirmed.

79.5 For the residential class, please confirm that savings due to both rate increases ("rate-driven") and RCR are estimated. If so, please explain the rationale for calculating those savings separately and discuss the potential for double-counting of savings.

Response:

The values in Tables E2-19 and E2-20 are the forecast for the RCR and Rate Driven impacts on the residential class. Please refer to BCUC IR 1.73.3 for further information about the RCR and rate-driven impact calculations.

79.6 Please clarify whether the AMI impacts presented in Table E2-22 are related to the residential class only.

Response:

Confirmed.

80.0 Reference: Exhibit B-1-1, Appendix E2, Tables 1.3, 1.4 and 1.6, pp. 2-4 and Table E2-17, p. 22; Appendix H1, Table H1-1b, p. 4

Load Forecast & Demand Side Management

FBC provides the following table in Appendix H1 (p. 4):

Table H1-1b: 2014-18 DSM Plan Savings

Program Area	2014 Plan Savings	2015 Plan Savings	2016 Plan Savings	2017 Plan Savings	2018 Plan Savings
Programs by Sector	*MWh*	*MWh*	*MWh*	*MWh*	*MWh*
Residential	5,800	5,783	5,615	5,511	5,407
General Service	6,200	6,304	6,408	6,512	6,616
Industrial	800	800	800	800	800
Total Programs:	12,800	12,887	12,823	12,823	12,823

80.1 For the residential class, please clearly explain where the annual DSM savings presented in Table H1-1b can be found in Table 1.3 (residential load forecast) in Appendix E2 (p. 2). For example, Table H1-1b indicates that residential DSM programs will save 5,800 MWh of electricity in 2014. However, in Table 1.3, the difference between the "Before saving & after rate-driven and RCR impacts" and "After savings" is 6,773 MWh. For each year, please reconcile the discrepancy or clarify the relationship between the two tables.

Response:

This discrepancy occurs as a result of the way that the DSM plan savings in Table H1-1b are attributed, disaggregated, and presented in the load forecast in Appendix E2 Table 1.3:

- When we undertake a DSM project the plan savings are attributed to that planning year. However for forecasting, we attribute the savings to the year following the project. For example, if a project with 12,000 kWh of savings was completed in December 2013 the plan shows all of those savings in 2013 whereas the forecast numbers account for 1/12 of the savings in 2013 (1,000 kWh of savings in December 2013) and the remaining 11/12 in 2014 (11,000 kWh of savings from January to November 2014). Thus, some of the plan savings are attributed to the follow year which creates a discrepancy in the presented values.
- For forecasting purposes we disaggregate a number of sub-categories of DSM that are not shown in the plan savings values. For example, 'Residential' in the plan savings contain the residential portion of the 'Wholesale' savings (for the City of Penticton and

the other municipal utilities in our territory) presented in the load forecast. Similarly the 'General Service' plan savings contain the '[Street] Lighting' and 'Irrigation' values shown in the load forecast. Please refer to the response to IR 80.4 for a discussion of the assumptions used for this disaggregation.

- Finally, the load forecast presents the DSM savings numbers as cumulative (the savings are cumulative over time) whereas the DSM plan shows them as incremental (the savings for each year are shown separately).

80.2 For the commercial class (general service), please clearly explain where the annual DSM savings presented in Table H1-1b can be found in Table 1.4 (commercial load forecast) in Appendix E2 (p. 3). For example, Table H1-1b indicates that commercial DSM programs will save 6,200 MWh of electricity in 2014. However, in Table 1.4, the difference between the "Before saving & after rate-driven impacts" and "After savings" is 13,493 MWh. For each year, please reconcile the discrepancy or clarify the relationship between the two tables.

Response:

Please refer to the response to BCUC IR 1.80.1.

80.3 For the industrial class, please clearly explain where the annual DSM savings presented in Table H1-1b can be found in Table 1.6 (industrial load forecast) in Appendix E2 (p. 4). For example, Table H1-1b indicates that industrial DSM programs will save 800 MWh of electricity in 2014. However, in Table 1.6, the difference between the "Before saving & after rate-driven impacts" and "After savings" is 2,088 MWh. For each year, please reconcile the discrepancy or clarify the relationship between the two tables.

Response:

Please refer to the response to BCUC IR 1.80.1.

FBC provides DSM savings by load class in Table E2-17 on p. 22 of Appendix E2:

TableE2-17: DSM with CoK (GWh)

	2013	2014	2015	2016	2017	2018
Residential	5.8	13.0	17.2	21.3	25.4	29.4
Commercial	6.1	13.5	17.6	21.7	25.7	29.6
Wholesale	3.5	7.8	10.2	12.6	14.9	17.2
Industrial	0.9	2.1	2.8	3.6	4.5	5.3
Lighting	0.4	0.8	0.8	0.8	0.8	0.8
Irrigation	0.4	0.7	0.9	1.0	1.2	1.4
Net DSM	17.1	37.8	49.5	61.0	72.5	83.8

80.4 Please explain how FBC calculated the DSM savings for the wholesale, lighting and irrigation classes presented in Table E2-17 in the absence of DSM programs for these classes (as per Table H1-1b). Also provide any assumptions used in the calculations.

Response:

As the explanation in the response to BCUC IR 1.80.1 states, the "load forecast presents the DSM savings numbers as cumulative (the savings are cumulative over time) whereas the plan shows them as incremental (the savings for each year are shown separately)." Thus, the [street] lighting savings do not show any additional growth (no savings are added) after the program ends in 2014 in Table E2-17.

Similar to the response in 80.1, for forecasting purposes we disaggregate a number of sub-categories of DSM that are not shown in the plan savings values. For example, 'Residential' in the plan savings contain the residential portion of the 'Wholesale' savings (for the City of Penticton and the other municipal wholesale utilities in our territory) presented in the load forecast. Similarly the 'General Service' plan savings contain the '[Street] Lighting' and 'Irrigation' values shown in the load forecast. The following data sources were used to disaggregate these data:

- We disaggregated wholesale using 2012 billing data to estimate the fraction of electricity sold to our wholesale customers.
- We estimated the residential and commercial portions of wholesale customer use as a fraction of the use in the City of Kelowna. For example, in 2012 the residential, commercial, and industrial customers in the City of Kelowna used 45%, 33%, and 22%,

of total electricity consumption, respectively. We applied these fractions to the total wholesale usage.

- Similarly, we applied historical DSM savings achieved in the City of Kelowna to estimate the fraction of savings by customer class in the rest of the wholesale customers.
- Finally, due to a lack of data, the ‘Industrial’, ‘Lighting’, and ‘Irrigation’ data presented in the load forecast include wholesale customers as well.

81.0 Reference: Exhibit B-1-1, Appendix E2, p. 24

Peak Demand Forecast

FBC states that "[t]he after DSM peak forecast was found by subtracting DSM capacity saving forecast, which is supplied by the DSM group, from the before DSM peak forecast for each month in each year."

81.1 Please explain the method and assumptions used to forecast the DSM capacity saving.

<u>Response:</u>

FBC multiplies the forecast of energy savings by a monthly capacity factor to forecast the DSM capacity saving. This capacity factor accounts for the monthly energy utilization rate and accounts for the peak in demand experienced in the winter and summer from heating and cooling loads, respectively.

82.0 Reference: Exhibit B-1-1, Appendix E2, p. 25

Concordance with the Load Forecast Technical Committee's Recommendations

FBC states that "[t]he Company checked the existing forecasting method with updated parameters for each load class and proposed appropriate changes to the residential customer count, the wholesale load and the lighting load classes. Please refer to Recommendation 8 for further detail."

82.1 Please explain what change FBC implemented for the Irrigation load class forecasting method and the rationale for doing so, since neither the Irrigation section of the Energy Forecast nor the Recommendation 8 section provide any indication of a change.

Response:

FBC confirms that there were no changes to the forecasting methods used to develop the demand forecast for the irrigation class.

E. PBR FORECAST – POWER PURCHASE EXPENSE

83.0 Reference: Exhibit B-1, p. 98

Power Purchase Expense (PPE)

In various tables of the Application, FBC shows "PPE Adjustment" of $2.25 million (Table C2-2; Table C2-3, Table C2-4).

83.1 Please explain the origin of this $2.2 million power purchases expense adjustment. Is this the flow through adjustment from purchases in 2011?

Response:

The $2.25 Million adjustment to the 2012 and 2013 power purchase forecast is not a flow through from 2011. The adjustment was applied to the 2012 and 2013 power purchase forecast to account for potential market savings. It is comprised of a $0.75 Million adjustment proposed by the Company in its initial power purchase forecast and a further $1.5 million adjustment ordered by the Commission in the 2012-2013 RRA Decision (G-110-12).

83.2 Please amalgamate these tables and expand the new table to include approved, actual, and contracted PPEs and another column showing gross load ($ and GWh) for the years starting in 2008.

Response:

Please refer to the tables below.

		2008 Approved	2008 Actual	Difference	2009 Approved	2009 Actual	Difference	2010 Approved	2010 Actual	Difference
		($000s)			($000s)			($000s)		
1	Brilliant	30,250	30,193	(57)	31,083	31,083	0	33,217	33,216	(1)
2	BC Hydro	36,772	34,140	(2,632)	38,443	34,565	(3,879)	44,836	29,485	(15,351)
3	Independent Pow er Producers	367	678	311	386	1,039	653	405	890	485
4	Market and Contracted Purchases	2,450	3,485	1,034	3,427	5,255	1,828	3,547	10,288	6,741
5	Surplus Revenues	(1,705)	(2,180)	(474)	(969)	(773)	196	(695)	(1,000)	(305)
6	Special and Accounting Adjustments	(122)	(834)	(712)	(208)	(577)	(369)	(265)	161	426
7	Balancing Pool	(484)	618	1,102	(209)	185	394	(136)	(1,075)	(939)
8	TOTAL (before adjustments)	67,529	66,100	(1,429)	71,953	70,776	(1,177)	80,909	71,964	(8,945)
9	PPE Adjustment	0		0	0		0	(500)		500
10	**TOTAL**	67,529	66,100	(1,429)	71,953	70,776	(1,177)	80,409	71,964	(8,445)
11	Gross Load (GWh)	3,396	3,399	3	3,400	3,478	78	3,509	3,324	(185)

		2011 Approved	2011 Actual	Difference	2012 Approved	2012 Actual	Difference	2013 Approved	2013 Forecast	Difference
		($000s)			($000s)			($000s)		
1	Brilliant	32,282	32,247	(35)	35,601	35,591	(10)	36,785	36,781	(4)
2	BC Hydro	46,811	28,006	(18,805)	51,426	26,037	(25,389)	54,482	31,773	(22,709)
3	Independent Pow er Producers	168	195	27	155	180	25	158	229	71
4	Market and Contracted Purchases	3,262	12,208	8,946	2,645	14,366	11,721	3,216	16,094	12,878
5	Surplus Revenues	(670)	(63)	607	(427)	0	427	(447)	(308)	139
6	Special and Accounting Adjustments	(377)	(861)	(484)	(1)	(162)	(161)	0	(738)	(738)
7	Balancing Pool	486	(213)	(699)	0	(13)	(13)	0	435	435
8	TOTAL (before adjustments)	81,962	71,519	(10,443)	89,399	75,999	(13,400)	94,192	84,266	(9,926)
9	PPE Adjustment	(750)	0	750	(2,250)	0	2,250	(2,250)	0	2,250
10	**TOTAL**	81,212	71,519	(9,693)	87,149	75,999	(11,150)	91,942	84,266	(7,676)
11	Gross Load (GWh)	3,472	3,452	(20)	3,490	3,413	(77)	3,534	3,461	(73)

All of the comparative tables included in this section of the Application suggest that there are substantial differences between forecast and actual PPE. Commission Staff prepared a summary of the variances in the table below:

	2012 Approved	2012 Actual	**2012 Variance**	2013 Approved	2013 Projection	**2013 Variance**
Total PPE (before Adjustments)	$ 89,399	$75,999	**<$13,400>**	$94,192	$84,266	**<$9,926>**
PPE Adjustment	<$2,250>	0	$2,250	<$2,250>	0	$2,250
Total PPE (after Adjustment)	$87,149	$75,999	**<$11,150>**	$91, 942	$84,266	**<$7,676>**

83.3 Does FBC agree that the variance in PPE for the last test period (2012-2013) is a credit of over $23 million before the PPE adjustment and over $18 million after the adjustment?

Response:

Yes, FBC agrees that the variance in the PPE for the last test period (2012-2013) is a credit of over $23 million before the PPE adjustment and over $18 million after the adjustment.

83.4 What is the approximate current balance in the PPE variance deferral account?

Response:

The balance of the PPE variance deferral account (which includes water fees) is approximately $12 million net of income tax. This balance will reduce the amount of revenue required in 2014.

83.5 What is the carrying cost on this credit deferral account?

Response:

The carrying cost of the PPE variance deferral account is approximately $0.3 million.

83.5.1 Is this deferral account proposed to be maintained during the 2014-2018 PBR period, with annual variances being flowed through in the following year's rates?

Response:

Yes. This deferral account, which was approved by Order G-110-12, is to be maintained over the 2014 – 2018 PBR period, with the annual variances being flowed through in the following year's rates.

FBC does not expect that future PPE variances from forecast will be comparable in size to those experienced in 2012 and 2013, largely due to changes in FBC's approach to forecasting PPE, which is discussed in Section C2 of the Application at page 99.

83.6 What is the annual rate impact for the amortization of the $18.8 million credit?

Response:

The annual rate decrement for 2014 for the full amortization of the $18.8 million credit (please also refer to the Table below) would be approximately 6.4%.

Power Purchase Parameters	Approved	Forecast / Actual	Variance
Power Purchase 2012	87,149	75,999	11,150
Power Purchase 2013	91,942	84,266	7,676
Total	**179,091**	**160,265**	**18,826**

FBC provides a PPE forecast for the years 2014-2018 in Tables C2-5 and C2-9.

83.7 Please confirm that the PPE forecast also includes capacity costs?

Response:

Confirmed.

84.0 Reference: Exhibit B-1, p. 98

Power Purchase Expense (PPE)

In past PBR's, PPE was forecast as an "at risk" item and was subject to the 50/50 sharing of overall Utility net earnings. At the time, some customers believed that this mechanism would provide an added incentive to FBC to find additional PPE savings from market purchases. In the last revenue requirement proceeding, FBC was approved PPE Deferral Account, where by the PPE would be trued-up in customer's rates in the following year.

84.1 Please compare and contrast the two approaches (of having PPE "at risk" and shared versus having PPE trued-up before sharing) in terms of their benefits for customers.

Response:

In its Decision regarding FBC's 2012-2013 RRA, the Commission made the following determination (page 34):

"The Commission Panel finds that a deferral account to capture variances between forecast and actual power purchase expense represents a reasonable attempt to manage uncertainty and approves establishing the Power Purchase Expense Variance Deferral Account as proposed by FortisBC. The Panel understands the complexity of managing the number of variables affecting the power purchase process and is in agreement that any positive or negative variances are most appropriately borne by the customer. The establishment of a Power Purchase Expense Variance Deferral Account is the most effective way to manage this process with variances being handled in customer rates in subsequent periods."

FBC agrees with this view. Since that time, customers have benefited from the establishment of the PPE deferral account in a number of different ways:

- Customers are receiving the full benefit of FBC's ability to capture market opportunities to generate savings. Over the 2012 and 2013 period, this value can be seen in the table provided in response to BCUC IR 1.83.6. Under the "at-risk" method (the 2007 PBR Plan), 50% of this value effectively flowed through to the shareholder through the earnings sharing mechanism.
- The PPE variance account also captures the impact on PPE of increases in BC Hydro rates. In previous years, the Company was not "at risk" for any increases in PPE due to changes in BC Hydro rates. Any BC Hydro increases were allowed to flow directly

through to customer rates based on forecast PPA purchases and were not offset by market savings generated in the same period.

- The establishment of the PPE variance deferral account has also allowed FBC to address the Commission's view that FBC's PPE forecasts were "overly conservative" (refer to page 35 of the Decision). As discussed in Section 2.4 of the Application (Exhibit B-1, pages 99-100), FBC has changed its approach to forecasting PPE expense in an effort to more accurately capture expected savings from market activities, which has resulted in a lower power purchase expense forecast. Customers will benefit from receiving some rate relief from having a lower PPE forecast embedded in rates, rather than in recovering 50% of the savings in future rates.

84.2 Did FBC undertake additional efforts to secure more low cost market sourced electricity in years when PPE was an "at risk" cost?

Response:

No. Regardless of whether it was a flow through or an "at risk" item, FBC actively manages the power purchase expense budget with the objective of minimizing power purchase expense while maintaining security and reliability of supply.

85.0 Reference: Exhibit B-1, p. 98

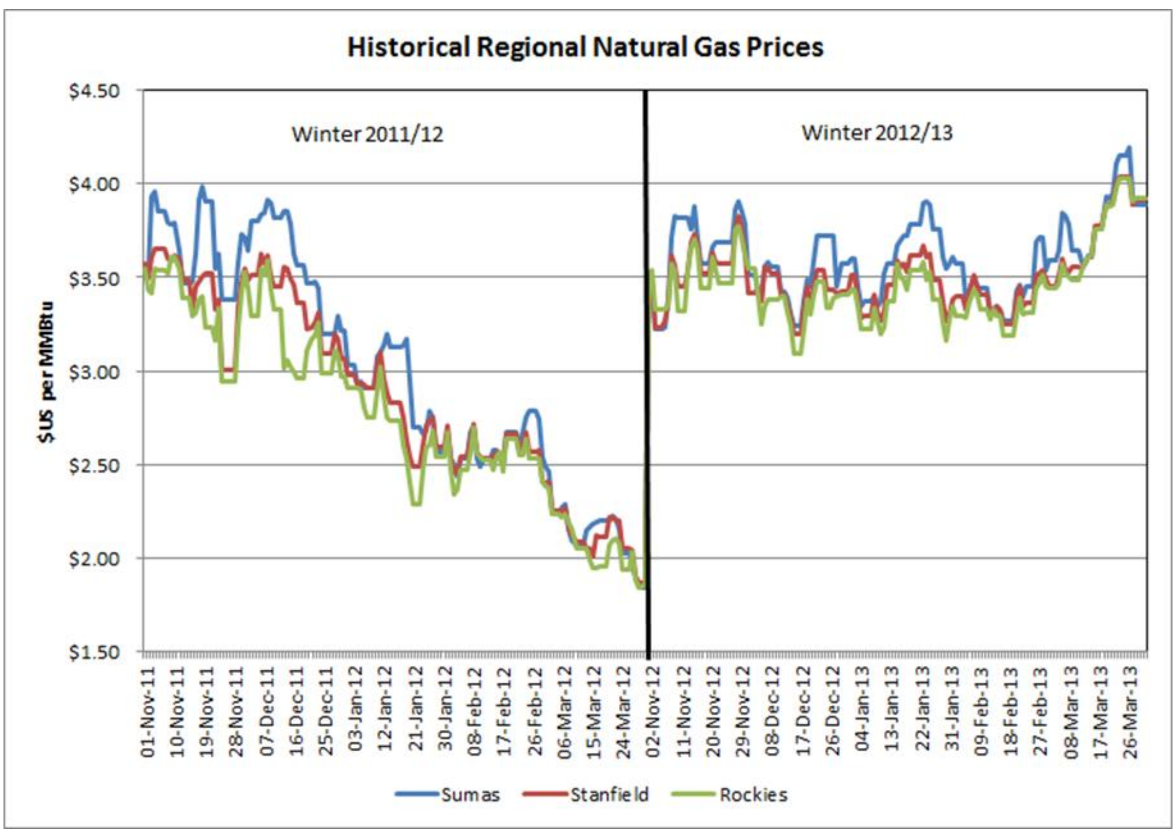
Power Purchase Expense (PPE)

FBC states that: "The winter of 2012/2013 saw average snow pack and upward pressure on the natural gas prices in the region. As a result, market prices in January through March of 2013 have been more volatile and generally higher than over the same period last year. Even with increased market prices compared to 2012, there have been opportunities to obtain market energy at rates below those of the BC Hydro PPA, however the overall savings are lower."

85.1 To what extent was there "upward pressure on the natural gas prices in the region" during the past winter?

<u>Response:</u>

Regional natural gas prices experienced upward pressure during the past winter of 2012/13 compared to the previous winter of 2011/12. This is illustrated in the following figure which compares several regional market gas prices for the two winters.



Regional gas prices were higher this past winter because North American gas prices were higher. Due to the interconnectedness of natural gas pipeline systems throughout North America, gas prices in all regions generally move together in response to overall changing supply and demand factors in North America. While regional basis differences will occur, overall, all prices generally move together.

There are several reasons for the increase in gas prices in North America during winter 2012/13. While natural gas production continued to increase slightly year-over-year due to the efficiencies and cost reductions achieved by gas producers, gas demand was up significantly. While winter 2011/12 was one of the warmest North American winters on record, winter 2012/13 was more normal and had some cold spells which resulted in increased residential, commercial and power generation demand. Furthermore, despite the higher prices in winter 2012/13 versus winter 2011/12, industrial demand increased as a result of the favourable gas prices. The result of this tighter supply and demand balance during winter 2012/13 resulted in North American natural gas storage levels falling below historical five-year averages by the end of March 2013. Subsequently, market gas prices increased.

85.2 In 2013 Projection, market purchases are higher than 2012 Actual even though snow pack was lower than 2012 and there was upward pressure on gas prices. Why?

Response:

Market and Contracted purchases are higher for the 2013 Projection than the 2012 Actual because the 2013 purchases were completed at a higher average cost, due to increased market prices in 2013 as compared to 2012.

86.0 Reference: Exhibit B-1, p. 99

Power Purchase Expense (PPE)

FBC states that: "In contrast, the 2014 forecast is based on a more detailed assessment of expected purchases from BC Hydro under the New PPA that takes into account FBC's expected load profile, the ability to lock in market savings in advance through contracted term purchases, and a forecast of any additional market savings that may be achieved in real time throughout the year through active management of the power supply portfolio."

86.1 Has FBC locked in any market savings from term contracts for 2014? If so, please provide details and how the prices were incorporated into the 2014 PPE forecast?

Response:

Yes, FortisBC has locked in market savings for 2014 based on term contracts. The details of those contracts are confidential due to commercial sensitivity. FortisBC received BCUC approval to enter into these agreements pursuant to Orders E-23-12 and E-11-13. In the orders, the BCUC also agreed to keep the information regarding these arrangements confidential.

The various arrangements have been incorporated into the power purchase forecast based on the information available at the time. As discussed in Section 2.4 of the Application (Exhibit B-1, page 99-100) from which the referenced quote is excerpted, this is the main reason for the decrease in the forecast purchases from BC Hydro and the increase in market purchases, resulting in an overall decrease in the PPE forecast.

FBC notes that at the time of the preparation of the PPE forecast for the Application, some of the arrangements had not yet been finalized. FBC will be providing updated costs that take into account the final agreements, among other things, as part of its planned Evidentiary Update.

87.0 Reference: Exhibit B-1, p. 100

Power Purchase Expense (PPE)

FBC states that: "The 2013 year end forecast is based on actual results to April 30, 2013 and an updated forecast to the end of 2013."

87.1 Please update Table C2-5 to include actuals for May through July and explain the changes to forecast 2013 due to spring weather.

Response:

The table below has been updated to include May through July actuals.

		2013 Projection	2014 Forecast	Difference
		($000s)		
1	Brilliant	36,781	35,764	(1,017)
2	BC Hydro	29,868	37,201	7,333
3	Independent Power Producers	256	162	(94)
4	Market Purchases	17,281	15,281	(2,000)
5	Surplus Revenues	(257)	(594)	(337)
6	Special and Accounting Adjustments	69	0	(69)
7	Balancing Pool	645	0	(645)
8	TOTAL	84,643	87,814	3,171
9	Gross Load (GWh)	3,461	3,464	3

May weather was consistent with what was filed in the Application, and resulted in no change to the 2013 Projection of power purchase expense. June and July has slightly cooler than forecast weather, resulting in a small reduction to gross load and a $120 thousand decrease to the 2013 projection of power purchase expense.

87.2 As a result of this update should there be any changes to forecast 2014 PPE? Why or why not?

Response:

The updates to the 2013 Projection do not result in any changes required for the forecast 2014 PPE. However, there are slight changes in prices of the contracts that FBC has entered into, and these updates will be put forward as part of the Evidentiary Update. Please refer to the response to BCUC IR 1.86.1.

88.0 Reference: Exhibit B-1, p. 101, Table C2-5

Power Purchase Expense (PPE)

Table C2-5 shows the 2013 projections and 2014 forecast of Power Purchase Expenses.

88.1 Why are the forecast 2014 purchases from BC Hydro significantly higher than 2013 when 2013 experienced average water conditions?

Response:

Even with average water conditions in the winter of 2012/2013, market prices at the Mid-C were lower in 2013 than they are forecast to be in 2014, and the Company is forecasting to purchase more BC Hydro energy and capacity in 2014. Also, the 2013 purchase amount is lower since the BC Hydro rate increase occurred on April 1, 2013, and the first three months of BC Hydro purchases in 2013 were at a lower rate than the rate used for the full year of 2014.

88.2 Why are the Brilliant purchases lower in 2014?

Response:

The Brilliant forecast for 2014 includes a "true-up" adjustment for prior years, which is the difference between the forecast and actual operating costs at the Brilliant Plant for 2011 and 2012, as allowed under the Agreements. This has resulted in a lower rate for 2014 as compared to 2013 due to a -$1.8 million adjustment due to the actual operating costs for 2011 and 2012. This true-up mechanism for purchases has been in place since FBC began purchasing Brilliant power.

89.0 Reference: Exhibit B-1, p. 102

New PPA with BC Hydro

FBC states that: "Under the New PPA, FBC continues to have access to 200 MW of capacity in any hour, plus all the associated energy. However, the access to energy based on BC Hydro's embedded cost is limited to 1,041 GWh per annum. Above 1,041 GWh, the cost for the energy increases to BC Hydro's proxy for long run marginal cost. In addition, under the New PPA, FBC is required to submit an Annual Energy Nomination by June 30th of each year, for energy deliveries in the following October to September Contract Year and is required to take and pay for 75 percent of the Annual Energy Nomination. Any energy taken above the Annual Energy Nomination is priced at 150 percent of the base rate. In addition, year over year FBC cannot change its Annual Energy Nomination by more than 20 percent."

89.1 How does the pricing under the new PPA compare to the current RS 3808?

Response:

The pricing for 200 MW of capacity and up to 1,041 GWh of energy per annum is the same under the current RS 3808 and new PPA. These costs are based on BC Hydro's embedded cost of energy and are consistent with BC Hydro's RS1827. Under the new PPA, the cost for any energy taken above 1,041 GWh is based on BC Hydro's Long Run Marginal Cost of energy, while under the current PPA, all energy was priced at BC Hydro's embedded cost of energy.

89.2 Are the restrictions in the new PPA a significant challenge to FBC compared to RS 3808? Please explain?

Response:

The restrictions in the New PPA do reduce the flexibility of the BC Hydro supply arrangement, however FBC believes that these can be managed properly and with minimal customer impacts through appropriate planning, updates to power supply operations procedures and monitoring both load and market conditions on an on-going basis. However, as explained in the application Section C-4, page 137, the sheer number of the changes in and of themselves is a significant challenge and will require additional resources.

90.0 Reference: Exhibit B-1, p. 102

New PPA with BC Hydro

FBC states that: "When market conditions allow, this may include entering into term firm market supply contracts to lock in savings and to allow a lower Annual Energy Nomination and reduce the take or pay commitment under the New PPA. Any such contracts will need to be completed prior to the June 30th deadline for the upcoming contract year beginning October 1."

90.1 Please detail the market supply contracts entered into for 2013-2014.

Response:

Please refer to the response to BCUC IR 1.86.1.

90.2 Do the contracts total 303 GWh as anticipated in the Application?

Response:

The contracted market purchases for the first year of the new PPA total 305 GWh.

91.0 Reference: Exhibit B-1, p. 102

New PPA with BC Hydro

FBC states that the 75 percent take or pay commitment to BC Hydro purchases allows for some additional market purchase savings and: "For the purposes of the 2014 Power Purchase Expense Forecast, FBC has estimated a further $2 Million reduction to BC Hydro expense based on current market forecasts."

91.1 Please show the methodology to establish how the $2 million reduction was estimated.

Response:

The estimate of the $2.0 million reduction was based on an assessment of the potential value of additional displacement of PPA energy with market purchases down to the 75% take or pay commitment based on an Annual Energy Nomination of 670 GWh (i.e. up to 167 GWHs). Based on a high level review of potential market prices over 2014, an average of $10/MWh savings from the PPA forecast was estimated to be achievable for the 167 GWh, equivalent to $1.7M. This number was rounded up to $2.0 million to account for additional capacity savings that may be achieved. This is an aggressive target that will be difficult to reach, but that the Company expects can be achieved with active management of the power supply portfolio. It should be noted, however, that the 25% flexibility above the take or pay amount is also required to help meet variances between actual and forecast load.

The actual amount of savings, in addition to what has already been locked in and included in the Power Purchase expense forecast, is highly dependent on the total FBC load, the timing of when the load occurs and Mid-C market prices. Any variance between estimated power purchase expense and actual expense will be captured by way of the power purchase deferral account mechanism.

92.0 Reference: Exhibit B-1, p. 103

Market Price forecast

FBC states that: "The hourly HLH forecast is used to estimate the cost of any peak demand shortfall. In order to get the energy from the MID-C to the FBC service territory, the Company applies a cost of $4 USD/MWh to the forecast Mid-C price as a transmission charge" and "The Company adds a 20 percent premium to the block forecast of heavy load energy to account for the peak hour premium."

92.1 Please show the methodology to estimate these premiums along with the actual average premiums in each of the last five years.

Response:

FBC's market activities are based on sales from or deliveries to FBC service territory. As such, transactions entered into with its counterparties are based on an "all-in" price, which includes energy, transmission, losses and any other tariff, such as greenhouse gas offsets. As such, FBC does not have a breakdown of transmission charges that are paid to move energy from the Mid-C to the FBC service territory.

The estimate of $4 USD/MWh is based on consultations with energy marketers, and verified by a review of Bonneville Power Administration's (BPA) "2012-2013 Transmission and Ancillary Service Rates" posted on the BPA website.[16] BPA's stated rates for Hourly Firm and Non-Firm transmission service is 3.74 mills per kilowatt hour. Additionally, BPA's Scheduling, System Control and Dispatch Service would apply at 0.59 mills per kilowatthour and Regulation and Frequency Response Service at 0.13 mills per kilowatthour. In total, the rate for wheeling energy from Mid-C to Teck Metals Line 71 would be 4.46 mills per kilowatthour, equivalent to $4.46 per MWh. In addition, BPA would charge 1.9% real power losses for every MWh wheeled from Mid-C to Teck Metals Line 71.

The 20% adder to the heavy load price forecast is an estimate of the expected increased cost of peak hour purchases, compared to the average heavy load price, since FBC will be required to purchase in the peak hours of the month, when prices are typically higher than the average heavy load price. A review of MID-C Market prices shows that the relationship between average daily MID-C prices and peak hour prices, with data from 2008 to 2012, is roughly 23 percent. This is calculated by taking the average MID-C price for each day between hour ending 7 and hour ending 22, and comparing to the peak hourly price for that day. This is calculated for each day, and averaged to determine annual numbers. The Mid-C data is based on Hourly Electricity Index provided by Dow Jones. The table below summarizes the data.

[16] http://transmission.bpa.gov/Business/Rates/default.cfm?page=cur.

Year	Average of Daily Mid-C Price (HE 7 to HE 22) ($/MWh)	Average of Maximum Daily Price ($/MWh)	Average Premium of Daily Peak Hour versus Monthly Average (%)
2008 Total	$ 59.47	$ 67.36	16%
2009 Total	$ 33.20	$ 38.93	19%
2010 Total	$ 33.87	$ 39.62	19%
2011 Total	$ 25.32	$ 37.04	46%
2012 Total	$ 18.48	$ 26.05	41%
Grand Total	**$ 34.07**	**$ 41.80**	**23%**

93.0 Reference: Exhibit B-1, p. 105

Water Fees

FBC states that: "Water fees are forecast to be down slightly in 2013 due to reduced plant entitlement use in 2012 caused by spill during the freshet because of low market power prices."

93.1 Please explain the circumstances that led to spilling water and why FBC did not pre-sell the electricity to avoid spilling?

Response:

In 2012, "spilling" CPA entitlements saved $6.04/MWh in water fee payments for 2013. Under the CPA, BC Hydro dispatches the actual system and therefore this does not represent a forced spill of water but rather an energy transfer from FBC to BC Hydro. The storage account procedures under the CPA are complex and this energy cannot be held for later use over the winter.

At the time of this surplus in 2012, market prices were low and it was not possible to sell this energy for more than $6/MWh, after taking into account transmission costs. It is difficult to predict the actual volume of surplus over the May through July period. If market prices are low, the Company retains sufficient supply ready at hand in case hot summer weather should occur. If the load occurs, the energy will be needed to meet load and potentially much higher prices will have been avoided during the hot weather. If the load does not occur then the energy must be "spilled" reducing water fees in the following year.

94.0 Reference: Exhibit B-1, p. 106 and Table C2-9

PPE Forecast summary

FBC states that: "Due to the expiry of the 5 year contract with Columbia Power Corporation on December 31, 2017, the Company anticipates an energy shortfall of 9 GWh in 2018, as the energy purchased under the BC Hydro PPA, limited to 200 MW in each hour, cannot be increased any further over the winter. The Company currently forecasts meeting this energy shortfall with spot market purchases which has been included in the estimates above."

94.1 In the context of the above quote, please explain the market purchases of 414 GWh in 2018 forecast?

Response:

The 414 shown in Table C2-9 is references thousands of dollars, not GWh. In 2018, the Company is forecasting an energy shortfall of 9 GWh, and is forecasting this will cost an average of $46/MWh, for a total of $414,000.

F. PBR FORECAST – OPERATION AND MAINTENANCE

95.0 Reference: Exhibit B-1, p. 112

O&M per customer

FBC states after accounting for the reclassification of certain expenditures in capital and the costs associated with MRS, "along with pension and Trail Office lease costs, O&M per customer, on an inflation-adjusted basis, is projected to be more than four percent lower in 2013 compared to 2010, a result which is partly attributable to economies of scale realized from the addition of the approximately 14,500 customers from the City of Kelowna."

95.1 Please expand the table to include the Actual and Approved O&M costs by department from 2008. Also include the total number of customers, and the O&M per customer for each of the years in nominal dollars including all O&M costs (pension, Trail office lease, etc.).

Response:

Table C4-1 has been expanded to include data back to 2008 with customer count and 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**

95.2 Why does FBC believe it appropriate to exclude the pensions and Trail office lease from the O&M per customer calculation? Please confirm that these costs are ratepayer expenses.

Response:

When comparing the 2010 to 2013 historical O&M per customer referred to in the preamble, it is appropriate to exclude the four cost components listed in the preamble, including pensions/OPEB expense and the Trail office lease, to provide a basis equivalent to those costs that had been included in the formula-driven O&M Expense under the 2007-2011 PBR Plan. The Trail Office and Pension/OPEB expenses had been excluded from the formula during the 2007-2011 PBR term because of their non-controllable and variable nature. Trail Office lease costs experienced a step increase in 2008 which the NSA recognized should not be included in the 2007-2011 O&M formula, and a decrease in 2013 with the buy-out of the lease. MRS and the reclassified capital costs are items arising after the Base O&M was set for the 2007-2011 PBR term.

All of the costs are ratepayer expenses, being added to the formula-driven portion of 2007-2011 O&M to determine Total O&M Expense.

95.3 What is the incremental O&M as a result of the City of Kelowna asset purchase? Please confirm that this incremental O&M was included in the 2013 Projection and 2013 Approved columns in the table.

Response:

The gross incremental O&M as a result of the City of Kelowna asset purchase for 2013 is $1,344.

Confirmed, this incremental O&M was included in the 2013 Projection and 2013 Approved columns in Table C4-1 at page 112 of the Application.

96.0 Reference: Exhibit B-1, p. 13, p. 51, and p. 113

Net Sustainable Savings

In the PBR Plan, FBC states that there are net sustainable savings of $452 thousand "against the approved O&M that are being embedded in the 2013 Base O&M for the future benefit of customers" (Exhibit B-1, p. 51)

FBC also provides a table illustrating the 2013 Approved and 2013 Projections for each O&M department and states that "approximately $452 thousand is being flowed through to the 2013 O&M Base." (Exhibit B-1, p. 113) A portion of this table is reproduced below for ease of reference.

	2013 Approved	Productivity (Sustainable Savings)	2013 Projection
Generation	2,492	64	2,556
Operations	20,816	122	20,938
Customer Service	7,541	(31)	7,510
Communications & External Relations	1,469	(29)	1,440
Energy Supply	1,124	-	1,124
Information Technology	2,974	14	2,988
Engineering and Project Management	2,791	31	2,822
Operations Support	1,252	(47)	1,205
Facilities	3,466	(77)	3,389
Environment, Health & Safety	953	-	953
Finance & Regulatory	4,271	(191)	4,080
Human Resources	1,874	-	1,874
Governance	2,373	117	2,490
Corporate	4,225	(425)	3,800
Total O&M	**57,621**	**(452)**	**57,169**

(Exhibit B-1, Table C4-2, p. 113)

96.1 In the column titled "Productivity (Sustainable Savings)," please confirm that a credit balance indicates sustainable savings, while a debit balance indicates incremental costs over the approved amounts for 2013.

Response:

Confirmed.

96.2 Please provide a breakdown of all the activities for each O&M department which would result in the over expenditure or savings indicated in the above table. Provide a short description on the nature of the incremental expenditures or savings.

Response:

Below is a breakdown of the activities that have resulted in the over expenditures and savings indicated in the above table.

	2013 Approved	Productivity (Sustainable Savings)	2013 Projection	Activities Resulting in Over Expenditure or (Savings)	Reference
Generation	2,492	64	2,556	Increased efforts to meet legislative dam safety requirements	Tab C Section 4 pg 123
Operations	20,816	122	20,938	No Specific Activity	-
Customer Service	7,541	(31)	7,510	No Specific Activity	-
Communications & External Relations	1,469	(29)	1,440	No Specific Activity	-
Energy Supply	1,124	-	1,124	N/A	-
Information Technology	2,974	14	2,988	No Specific Activity	-
Engineering and Project Management	2,791	31	2,822	No Specific Activity	-
Operations Support	1,252	(47)	1,205	Reduction in labour for Supply Chain and vehicle costs for Fleet	Tab C Section 4 pg 149
Facilities	3,466	(77)	3,389	Reduction in labour due to integration	BCUC IR1 132.3
Environment, Health & Safety	953	-	953	N/A	-
Finance & Regulatory	4,271	(191)	4,080	Lower external auditor fees and labour	BCUC IR1 134.2
Human Resources	1,874	-	1,874	N/A	-
Governance	2,373	117	2,490	Higher insurance premiums and appraisal fees	-
Corporate	4,225	(425)	3,800	Lower Board Costs, Executive labour and non-labour costs, partially offset by increased Fortis Inc charges.	Tab C Section 4 pg 170-172
Total O&M	**57,621**	**(452)**	**57,169**		

FBC states "Integration driven opportunities in 2012 included the Human Resources (HR) department where the employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated and aligned between electric and gas utilities…In the Environmental Health and Safety department, many processes, programs, operating standards and roles have been aligned between the gas and electric utilities, contributing to the efficiencies realized." (Exhibit B-1, p. 13) (Emphasis added)

96.3 Given the statements above regarding the integration of certain O&M functions in 2012 with FEI, please explain why there are no sustainable savings observed for the HR department and the EH&S departments for 2013, as shown in Table C4-2 of the Application?

Response:

The integration of the two utility divisions' EH&S and HR groups enabled the analysis of productivity opportunities. Within EH&S, the bulk of integration synergies have been achieved, and the Company does not anticipate continual significant synergies to arise, given the current structure and ongoing, operational requirements to provide safe and reliable customer service.

This is also the case for the HR group. Although there are no sustainable savings observed for 2013, integration has allowed the HR group to provide internal service improvements through many of its teams, along with managing increased labour and regulatory activity without increasing O&M. Specific examples of these benefits that have been achieved as a result of integration include:

- Increased pension consulting costs have been absorbed within the cost centre with ongoing work undertaken to mitigate contribution rate increases and pension expenses;
- Increased costs have been absorbed to support an important part of FBC's employee branding through its community giving programs, including facilitating alignment of electric utility employee programs with those already offered in the gas utility; and
- Training resources have been leveraged across both utilities which has resulted in increased capacity to build new apprenticeship opportunities as part of the workforce plan to fill skilled trades (such as CPC Technologist and PSD) in the future. This has also resulted in increased business and leadership training opportunities to support career development and workforce planning without increasing operating costs. This also supports succession and workforce planning efforts.

97.0 Reference: Exhibit B-1, pp. 53, Table C4-2, p. 113

Base O&M, O&M Tracked Outside of the Formula and City of Kelowna

97.1 Please recreate Table C4-2 in the format provided below excluding O&M costs that are tracked outside of the PBR formula (i.e. Pension/OPEB [O&M portion], Insurance and the AMI Project) and excluding the City of Kelowna.

						2013 Deferrals			
O&M By Department	2012 Approved	2012 Actual	2013 Approved	Productivity (Sustainable Savings)	2013 Projection	PST	MRS	Incremental O&M	2013 Base
				($ thousands)					
Generation									2,492
Operations									20,816
Customer Service									7,541
Communications & External Relations									1,469
Energy Supply									1,124
Information Technology									2,974
Engineering and Project Management									2,791
Operations Support									1,252
Facilities									3,466
Environment, Health & Safety									953
Finance & Regulatory									4,271
Human Resources									1,874
Governance									2,373
Corporate									4,224
Total O&M									**57,621**

Response:

The recreated Table C4-2 has been provided below. AMI is not included as there are no related O&M Expenses in 2013.

										2013 Deferrals				
	2012 Approved	2012 Actual	2013 Approved	City of Kelowna	Pension/ OPEB	Insurance	2013 Adjusted	Productivity (Sustainable Savings)	2013 Projection	PST	Pension	MRS	Incremental O&M	2013 Base
Generation	2,282	2,331	2,492		(269)		2,223	64	2,287	3	137		350	2,777
Operations	19,920	19,730	20,816	(488)	(2,248)		18,081	122	18,203	53	769			19,025
Customer Service	6,624	6,766	7,541	(835)	(814)		5,892	(31)	5,861	15	333			6,209
Communications & External Relations	1,431	1,244	1,469		(159)		1,310	(29)	1,281	14	35			1,331
Energy Supply	1,069	986	1,124		(121)		1,003	-	1,003	2	52			1,057
Information Technology	2,841	2,925	2,974		(321)		2,653	14	2,667	36	124			2,827
Engineering and Project Management	2,701	2,615	2,791		(301)		2,490	31	2,521	5	141	900		3,567
Operations Support	1,223	1,240	1,252		(135)		1,117	(47)	1,070	2	51			1,123
Facilities	3,685	3,596	3,466		(374)		3,092	(77)	3,015	16	30		(909)	2,152
Environment, Health & Safety	925	894	953		(103)		850	-	850	1	59			910
Finance & Regulatory	4,392	3,823	4,271		(461)		3,810	(191)	3,619	6	201			3,826
Human Resources	1,840	1,816	1,874		(202)		1,672	-	1,672	4	80			1,756
Governance	1,792	2,134	2,373	(22)	(256)	(1,588)	507	117	624	10	31			665
Corporate	4,118	3,444	4,225		(456)		3,769	(425)	3,344	11	115			3,470
Total O&M	**54,843**	**53,544**	**57,621**	**(1,344)**	**(6,222)**	**(1,588)**	**48,467**	**(452)**	**48,015**	**180**	**2,158**	**900**	**(559)**	**50,694**

Note: AMI 2013 tracked outside of the PBR formula is zero

98.0 Reference: Exhibit B-1, p.13 and p. 113

Base O&M, Table C4-2

98.1 If the savings from the O&M departments are considered "sustainable" then is it also true that in the departments where there are no savings (in fact, where there are incremental costs), these costs would also be "sustained" in the future, meaning that those additions to O&M would be included in the O&M Base and continue to grown annually with the PBR formula.

Response:

Yes. The adjustment to the 2013 Approved O&M to determine the 2013 Base O&M is at the Total O&M level, consistent with the premise in the proposed PBR Plan that O&M is determined at the aggregate level, leaving the utility to determine the allocation of the overall funds available as needed.

98.1.1 Does this indicate that FBC is proposing to "true" up the 2013 forecast (the "2013 Projection"), then making this trued up amount to be the 2013 Base? Why or why not?

Response:

No. FBC is not proposing to change the 2013 Base O&M from that proposed in the Application. As stated at page 50 of Section B6.2 (lines 28-31), the Company believes that the starting point for the O&M Base should be the Approved 2013 O&M value which has undergone a full review through an oral public hearing, with a minimal number of necessary adjustments. FBC proposes to reduce the Approved 2013 O&M by $0.452 million to recognize net sustainable savings. The proposed Base O&M represents the ongoing level of expenditures required to operate the Company over the term of the PBR Plan.

98.2 Please explain why any over expenditures from 2013 Approved budget should be incorporated into the 2013 Base?

Response:

Please refer to the response to BCUC IR 1.98.1.

98.3 Should the Commission consider any variances in the 2012 Approved and 2012 Actual in the determination of the 2013 Base? Why or why not?

Response:

No. The circumstances of the 2012 variance from Approved are such that 2012 is not a suitable base on which to establish a PBR formula. As stated in the Application at page 112 in Section C4.2, the fact that the Commission's decision on 2012 revenue requirements was not issued until August of 2012 resulted in some expenditures being delayed (please refer to the response to BCUC IR 1.101.2). These delayed expenditures are required in 2013 and future years to provide the necessary level of utility service; for that reason, the lower spending in 2012 is not representative of sustainable reductions over the term of the PBR Plan.

98.4 Should the Commission use the 2013 Approved O&M budget (adjusted for PST and Pension only) as the 2013 Base in the PBR formula? Why or why not?

Response:

In addition to the PST and Pension adjustments, FBC's 2013 Approved budget includes a productivity/savings adjustment and budget changes for Generation, MRS and Trail office lease, to arrive at the 2013 Base O&M Expense.

The productivity adjustment represents a one-time decrease to the 2013 Approved O&M that will be sustained over the term of the PBR Plan.

The Generation and MRS adjustments are necessary expenditures in every year of the PBR period beginning in 2014 and must be included in O&M Expense at the full amount required to perform the associated activities. The justifications for these costs are provided in Sections C4.4 and C4.10. The adjustment to the Facilities budget reflects the reduction in lease costs associated with the purchase of the Trail office and is not required during the PBR term. The total 2013 Base O&M represents the amount of O&M Expense required to operate the Company over the proposed PBR Period.

If the 2013 Approved O&M Expense was adjusted only for PST and Pension as suggested in the question, the resulting 2013 Base O&M would be $59.959 million, compared to $59.848 million as proposed in the Application.

98.5 Please explain how the Commission can determine whether any of the 2013 over expenditures or savings are related to efficient operations or simply non-expenditures of an already approved budget?

Response:

The reasons for the 2013 forecast O&M variances are explained in the response to BCUC IR 1.96.2.

99.0 Reference: Exhibit B-1, p. 50

Base O&M – City of Kelowna

"FBC has used the 2013 Approved O&M as the starting point for the O&M formula. A number of adjustments are then made to this figure to arrive at the "2013 Base".

FBC describes "2013 Approved O&M" as "Order G-110-12 regarding FBC's 2012 and 2013 Revenue Requirements, plus the O&M impact of the acquisition of the City of Kelowna utility assets, approved by Order C-4-13." (Exhibit B-1, Footnote #26, p. 26)

On page 19 of the City of Kelowna Application[17], FBC states "The incremental increase arises due to these costs, which were formerly paid by the City, now being paid by FortisBC. This includes the operations and maintenance of the assets and the customer service functions. In 2013, approximately 62% of the costs are associated with customer service functions, composed primarily of the interim continuation of the Corix contract. After 2013, once FortisBC performs these functions in-house, the customer service component falls as a percentage of the total and levels off at 36% after 2015. There are no incremental administrative costs associated with the addition of the City's assets or customers." (Exhibit B-1, City of Kelowna Application, p. 19)

99.1 Please complete the following schedule as a breakdown of "2013 Approved O&M" between O&M approved by Order G-110-12 and incremental O&M related to the acquisition of the City of Kelowna utility assets.

O&M By Department	2013 Approved by Order G-110-12	2013 City of Kelowna	Total 2013 Approved
		($ thousands)	
Generation			2,492
Operations			20,816
Customer Service			7,541
Communications & External Relations			1,469
Energy Supply			1,124
Information Technology			2,974
Engineering and Project Management			2,791
Operations Support			1,252
Facilities			3,466
Environment, Health & Safety			953
Finance & Regulatory			4,271
Human Resources			1,874
Governance			2,373
Corporate			4,224
Total O&M			**57,621**

[17] In the matter of an Application by FBC for the Purchase of the Utility Assets of the City of Kelowna (City of Kelowna Application)

Response:

The table below provides the breakdown of "2013 Approved O&M" between O&M approved by Order G-110-12 and incremental O&M related to the acquisition of the City of Kelowna utility assets.

O&M By Department	2013 Approved by Order G-110-12	2013 City of Kelowna	Total 2013 Approved
	(Thousands)		
Generation	2,492	-	2,492
Operations	20,328	488	20,816
Customer Service	6,706	835	7,541
Communications & External Relations	1,469	-	1,469
Energy Supply	1,124	-	1,124
Information Technology	2,974	-	2,974
Engineering and Project Management	2,791	-	2,791
Operations Support	1,252	-	1,252
Facilities	3,466	-	3,466
Environment, Health & Safety	953	-	953
Finance & Regulatory	4,271	-	4,271
Human Resources	1,874	-	1,874
Governance	2,351	22	2,373
Corporate	4,225	-	4,225
Total O&M	**56,276**	**1,344**	**57,621**

99.1.1 Please discuss how FBC derived the approved and projected 2013 *incremental* O&M related to the City of Kelowna purchase.

Response:

The forecast incremental O&M related to the utility assets formerly owned by the City of Kelowna was derived based on FBC's past experience operating the former City of Kelowna utility assets (under the terms of a subcontract with FPHI, pursuant to the Company's Code of

Conduct and Transfer Pricing Policy). Previously, the incurred O&M expenditures would have been billed to FPHI, however as FBC is now the owner of these assets the associated O&M costs become part of FBC's overall O&M expenditures. The 2013 incremental O&M related to the City of Kelowna purchase is detailed in the application for a CPCN for the Purchase of the Utility Assets of the City of Kelowna, and is also reflected in the compliance filing dated April 9, 2013 which incorporated the adjustments set out in Directives 2 through 10 of Order C-4-13.

99.1.2 In Figure 2 of Exhibit B-1 of the City of Kelowna Application, the *incremental* O&M related to the City of Kelowna only is projected to decline from $1,344 thousand in Forecast 2013 to $1,192 thousand in Forecast 2017. Please discuss why, in FBC's opinion, it is appropriate to include the incremental City of Kelowna O&M in the 2013 Base O&M which is then included in the formulaic approach.

Response:

As the addition of the City of Kelowna distribution assets (and the approximately 15,000 customers associated with these assets) drive an incremental increase to FBC's ongoing O&M requirements, it is appropriate to include the 2013 forecast O&M related to these assets as part of the 2013 Base. The fact that FBC is forecasting a slight decline in the incremental O&M requirements related to these assets is not considered determinative as to whether or not these expenditures should be included under the PBR formula. Indeed, these incremental O&M expenditures are relatively stable with a difference between the 2013 and 2017 forecast incremental O&M of only $0.152 million, or about 0.25 percent of the 2013 Base O&M. FBC does not consider this slight forecast decrease to be of sufficient magnitude to require either a downward adjustment to the 2013 Base, or exclusion of the incremental O&M related to the former City of Kelowna assets from the PBR formula.

100.0 Reference: Exhibit B-1, p. 52

Base O&M - O&M Tracked Outside of the Formula: Pension and OPEB Expense

"The pensions and OPEBs were excluded from the formula in the 2007 PBR and considered "flow through" items due to their recognized uncontrollable nature."

100.1 Please discuss the degree of 'controllability' that FBC has over forecasting Pension and OPEB expense for a period of one year.

<u>Response:</u>

FortisBC has essentially no "controllability" over forecasting its pension and OPEB expense for a period of one year.

While FortisBC will provide estimates of interim pension and OPEB expense provided by its third party external actuary prior to the year for which rates are being set as part of the Annual Review, the actual pension and OPEB expense for a given year will not be determined for several months later. During this time lag, actuarial assumptions for which the Company has limited or no control over, will vary, thus creating a variance between forecasted and actual pension and OPEB expense.

These non-controllable actuarial assumptions include the discount rate (which is based on Corporate AA 5 bond yields), the expected return of pension plan assets, the rate of inflation, the rate of increase in pensionable earnings, the rate of increase in extended health care costs for retired employees, the rate of increase of MSP premiums, rates of mortality and rates of termination of employment. These items are generally outside the control of the Company and are either based on individual employee's decisions (like the rates of retirement), based on market conditions (like the discount rate), and some based on experiences of plan members, like the mortality rates of plan members. The biggest driver of expense increases in recent years has been discount rates. As a result, the costs of the defined benefit pension plans and other post-employment benefits are outside of the Company's control.

101.0 Reference: Exhibit B-1, pp. 112-113

O&M – 2012 Postponed Expenditures

"While 2012 O&M was approximately $1.3 million lower than the approved amount, resulting from certain expenditures being postponed pending an RRA decision that was issued in August of that year, 2013 O&M is projected to be within 1.0 percent of approved." (p. 112)

101.1 Please confirm, or explain otherwise, that the "2013 Projection" figures represent the projected actual 2013 expenditures.

Response:

Confirmed.

101.2 Please provide a list, by department, of O&M expenditures deferred from 2012 to 2013. For each department, please provide a description of the deferred expenditures.

Response:

2013 O&M projection has not been increased to include expenses from 2012. 2012 O&M expenditures were lower as the 2012-2013 Decision was issued in August of 2012, therefore expenditures did not occur during the year as originally planned. For example, there was a delay in hiring of staff.

102.0 Reference: Exhibit B-1, p. 113

Base O&M - 2013 Sustainable Savings

"The 2013 O&M savings of approximately $452 thousand is being flowed through to the 2013 O&M Base which is used to determine the amount of O&M for the 2014 – 2019 PBR Period, and results in a sustainable benefit to customers."

102.1 For each department included in Table C4-2, please provide 2013 projected gross savings and 2013 projected gross cost overruns, totaling the net sustainable savings.

Response:

Please refer to the response to BCUC IR 1.96.2.

103.0 Reference: Exhibit B-1, p. 114

Executive Compensation

FBC states that: "The Company's executive compensation program involves four main elements:

1. base pay;
2. short term incentive pay;
3. long term incentive pay; and
4. benefits."

103.1 Please provide the total cost and average cost/ executive for each of the four categories for each year from 2008?

Response:

Please refer to the table below for total and average costs relating to current executives employed by FBC for: base pay, short-term incentive pay, long-term incentive pay and benefits for 2008 to 2014. (Note that a portion of this compensation is recovered from affiliates as per BCUC IR 1.225.1.)

Total and Average Executive Compensation Elements for 2008-2013

	Total FBC Executives			
	Base Pay	Short Term Incentive Pay	Long Term Incentive Pay	Benefits
2008	$ 1,205,398	$ 580,000	$ 395,784	$ 310,302
2009	$ 1,347,138	$ 651,000	$ 450,704	$ 331,331
2010	$ 1,391,038	$ 769,000	$ 407,009	$ 330,080
2011	$ 1,497,800	$ 1,055,000	$ 472,044	$ 414,079
2012	$ 1,555,325	$ 1,021,000	$ 446,344	$ 480,745
2013*	$ 1,631,900	$ 1,040,738	$ 474,787	$ 75,333

	Average FBC Executives			
	Base Pay	Short Term Incentive Pay	Long Term Incentive Pay	Benefits
2008	$ 241,079.68	$ 116,000.00	$ 79,156.80	$ 62,060.32
2009	$ 224,523.03	$ 108,500.00	$ 75,117.33	$ 55,221.81
2010	$ 231,839.67	$ 128,166.67	$ 67,834.83	$ 55,013.28
2011	$ 299,560.00	$ 211,000.00	$ 94,408.80	$ 82,815.89
2012	$ 311,065.00	$ 204,200.00	$ 89,268.80	$ 96,148.91
2013*	$ 326,380.00	$ 208,147.60	$ 94,957.39	$ 15,066.53

** Budgeted & estimated amounts, Pension earnings not included*

It should be noted that:

- Base pay = base pay earnings;
- Short term incentive = STI earned in the calendar year, paid in the following year;
- Long term incentive = Stock options valued using the Black-Scholes Option Pricing Model; and
- Benefits = health benefits, pension, allowances, vacation payout.

The total and average compensation for each FBC employed executive has increased per executive, as noted in the table above. However, the table does not reflect the fact that each executive's scope has increased, and the fact that total executive labour, as per Table C4-36, has decreased since 2010. This is a result of the overall reduction in number of executives employed between FEI/FBC and the sharing of this smaller executive team between utilities.

104.0 Reference: Exhibit B-1, p. 115

Executive Employees – Stock Based Plans

"FBC provides its long term incentive through participation in Fortis Inc. stock based plans. The stock option is funded by the shareholder and is not included in the revenue requirements."

"Stock based compensation includes stock options and Performance Share Units (PSUs) with both expensed to the shareholder."

104.1 Please confirm, or explain otherwise, that all expenses related to stock options and PSUs are expensed to the shareholder, including mark-to-market adjustments and any real or notional dividends.

Response:

FBC executive compensation related to stock options or PSUs (including market to market adjustments and real or notional dividends) are expensed to the account of the shareholder, thus no associated costs are included in the Revenue Requirements.

104.1.1 Please provide the total cost of any stock option or PSU expense included in the approved revenue requirements in each of 2012 and 2013.

Response:

FBC executive compensation related to stock options or PSUs (including market to market adjustments and real or notional dividends) are expensed to the account of the shareholder, thus no associated costs are included in the Revenue Requirements.

FBC states that: "FBC provides its long term incentive through participation in Fortis Inc. stock based plans. The stock option is funded by the shareholder and is not included in revenue requirements."

104.2 How is the Balanced Scorecard used to set long term incentives?

Response:

The balanced scorecard is not used to set long term incentives.

104.3 Does the statement above suggest that item 3. Long term incentive pay on page 114 is paid entirely by the shareholder, including any pension implications? If not, please explain.

Response:

Long term incentive pay for FBC's executives is paid entirely by the shareholder.

105.0 Reference: Exhibit B-1, p. 116

Labour and Benefit Inflation

"In all departments, the forecast labour inflation and benefit loadings have been applied to the forecast labour force for 2013."

105.1 Please confirm, or explain otherwise, that the labour and benefit loadings discussed on p. 116 were used in determining the 2013 Approved Labour O&M, rather than the 2013 Projection or 2013 Base Labour O&M.

Response:

Forecast labour inflation and benefit loadings were used in determining the 2013 Approved Labour O&M. The 2013 Projection and 2013 Base O&M are also derived from forecast labour costs and benefits loadings.

106.0 Reference: Exhibit B-1, p. 118

Productivity

FBC states that: "Future integration opportunities are expected to be more complex and dependent on the Company's ability to overcome challenges around union issues and IT platforms and differences in the nature of the electric and gas operations."

106.1 Please provide a more fulsome explanation of the challenges noted above.

<u>Response:</u>

Systems and their support structures have been designed around the business needs for each organization. Integration requires alignment of business practices of the two utilities in order to further share Information Systems. The IS department continues to identify and assess alignment and integration opportunities between the two organizations, because system alignment and integration can require considerable investment and must be considered when estimating total benefits. Safety, customer service and cost are primary considerations to ensure integration plans and strategies deliver positive value.

Further integration opportunities could be more complex with respect to union issues because of jurisdictional considerations associated with bargaining units and collective agreements. FBC continues to support its operational departments with managing different job descriptions, rates of pay and collective agreements for union employees within the same department. However, FBC is not in a position to make unilateral decisions on some of these issues. Progress may be gained either through collective bargaining or with the co-operation of the unions representing FBC's different bargaining units as FBC continues to balance potential opportunities against customer impacts and costs.

107.0 Reference: Exhibit B-1, p. 118

Demographics

FBC states that: "Between 2013 and 2018, 552 employees, or roughly 24 percent of the total employee population of the combined gas and electric utilities are eligible to retire with unreduced pensions."

107.1 What percentage of the existing Executive and Management and Exempt employees would reach the age of 65 during the period from 2013 - 2018?

Response:

While the retirement figures noted in the preamble include employees from both the gas and electric utilities, based on FBC's workforce as of August 23, 2013, 5.45% of M&E employees (9 out of 165) will reach age 65 during 2013 – 2018.

108.0 Reference: Exhibit B-1, p. 122

Generation

FBC states that: "With the completion of the ULE program, the Company will return to its full maintenance program at the facilities comprised of both routine (1 to 2 year intervals) and non-routine (3, 5, 10, 15 year intervals) tasks."

108.1 Please explain why the completion of the ULE program did not result in a significant reduction in employees within the Generation department?

Response:

As noted on page 121, "The department employs approximately 100 employees annually comprised of approximately 65 full time and 30-35 temporary employees, depending on the type of work and the timing of such work." The ULE program commenced in 1998 and the last ULE (except for the UBO old plant) was completed in 2011. Approximately 30 to 50% of the ULEs workforce comprised of temporary employees so the annual temporary employee count varied from 1998 to 2011. Additionally, in 2012, following completion of all the ULEs, the number of Term-Hourly staff was further reduced by 9. Completion of the ULE has therefore seen a reduction in Term-Hourly staffing levels.

109.0 Reference: Exhibit B-1, p. 122

Generation

FBC states that: "Surveys by Centre for Energy Advancement through Technological Innovation (CEATI) of utility best maintenance practices indicate that major electrical inspection is required after 10 years of continuous operation (generally taken to be 8,000 hours per year) and major mechanical inspection typically every 20-30 years."

109.1 Which utilities in Canada adhere to the CEATI maintenance practices?

Response:

There are 39 Canadian utilities that are sponsors/members of CEATI as of January 2013. The utilities are:

- AltaLink
- ATCO Group
- BC Hydro
- Brookfield Renewable Power
- Capital Power
- Columbia Power
- Enbridge Gas Distribution
- ENMAX Power
- EnWin Utilities
- EPCOR
- FortisAlberta
- FortisBC
- FortisOntario
- Great Lakes Power
- Greater Sudbury Hydro
- H2O Power
- Horizon Utilities
- Hydro One Networks
- Hydro Ottawa
- Hydro-Quebec
- Manitoba Hydro
- Nalcor Energy
- Natural Resources Canada
- New Brunswick Power
- Newfoundland and Labrador Hydro
- Newfoundland Power
- Nova Scotia Power
- Ontario Ministry of Natural Resources
- Ontario Power Authority

- Ontario Power Generation
- PowerStream
- Rio Tinto Alcan
- Saskatoon Light & Power
- SaskEnergy
- SaskPower
- Toronto Hydro
- TransAlta
- TransCanada Pipelines
- Yukon Energy

CEATI publications are generally in the form of industry best practices, benchmarking and guides developed by industry experts. These are adopted or endorsed by the sponsoring member utilities, as applicable.

109.2 Are the CEATI maintenance practices required by the Canadian Electrical Association, B.C. MRS or B.C. electrical inspector?

Response:

CEATI is involved in the compilation of best practices and development of guidelines, which are used widely as the de facto standard across the 60 utilities worldwide who participate in their hydro program. While the CEA is not responsible for approving the CEATI standards, many of CEATI's sponsoring utilities endorse the materials produced within the CEATI hydro program as their standard.

A few examples of such maintenance guidelines include project #0329 Hydroelectric Turbine-Generator Units Guide for Erection Tolerances and Shaft System Alignment, and project #0354 Maintenance Overhaul Guide for Hydroelectric Turbines. Further examples can be found on the CEATI portal site: www.my.ceati.com.

110.0 Reference: Exhibit B-1, p. 122

Generation

FBC states that: "Ensuring compliance with the changing Dam Safety legislation continues to be a priority for FBC. For example, dam safety inspections are required to be conducted at each plant classified as Extreme every 7 years and 10 years for each plant classified as High/Very-High, to ensure compliance with BC Dam Safety Regulation 44/2000 including amendments up to BC Reg 163/2011, September 12, 2011 (BCDSR). As a result of the recent changes, Corra Linn plant is now classified as Extreme and inspections must be done every 7 years."

110.1 Is this change to the inspection period for dam safety at Cora Linn not a modest cost item to be included in base capital?

Response:

The change in inspection period is a modest cost item. The increase in cost was triggered by the increased design criteria imposed at the next level of classification. For example, the Canadian Dam Safety Association recommends that dams classified as Very High consequence be designed to withstand an earthquake with an annual exceedance probability of 1/5000 while dams classified as Extreme consequence be designed to withstand an earthquake with an annual exceedance probability of 1/10000. Since these costs relate to inspections they are normally included in the O&M component of the budget.

110.2 When was the last inspection done at Cora Linn and what was the cost?

Response:

The last inspection was completed at Corra Linn during 2011 and 2012 for a total cost of $77,850.

111.0 Reference: Exhibit B-1, p. 123 & Table C4-4

Generation

FBC states that: "Generation O&M expenses are subject to a relatively small degree of fluctuation from year to year…"

111.1 Please explain the referenced statement when Table C4-4 indicates a 37 percent increase in Generation O&M over the three year period from 2010 Actual to 2013 Base?

Response:

The statement "Generation O&M expenses are subject to a relatively small degree of fluctuation from year to year …" refers to the prior years 2010-2012.

Table C4-4: Generation O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 1,600	$ 1,703	$ 1,854	$ 1,887	$ 1,916	$ 2,357
Non-Labour	617	696	477	605	640	689
Total O&M	**$ 2,217**	**$ 2,399**	**$ 2,331**	**$ 2,492**	**$ 2,556**	**$ 3,046**

The annual Generation O&M 2013 budget of $2.492 million includes the cost of all routine maintenance activities and approximately $0.2 million for various non-routine activities including items introduced as part of recent regulatory requirements. Considering the operating hours and the condition of the existing equipment, the Generation department plans to schedule major inspections on each unit once every 15 years, in line with industry best practices. The cost of this was not included in any recent prior budget submissions because it was not necessary since the ULE program was ongoing and each of the units was upgraded.

111.2 Why have Generation O&M costs risen 10 percent in the past year?

Response:

The increase from $2.331 million to $2.556 million was driven primarily by the increase in Non-labour expenses from $0.477 million to $0.640 million. On page 123 of the Application it is noted: "The increase in non-labour expenses was primarily due to legislative changes. For example, new dam safety regulations were introduced in September, 2011 (BCDSR), increasing the frequency of dam safety reviews." Each dam safety inspection, for example, costs $77,850 as noted in the response to BCUC IR 1.110.2.

111.3 Why is the 2013 Projection used as a starting point to inflate the 2013 Base rather than using the 2013 Approved?

Response:

The O&M forecasts shown in Section C4 (including Generation expenses in Tables C4-4 and C4-5) are inputs to the Company's high-level forecast of future trends and challenges for FBC. The expected 2013 costs are an appropriate starting point from which to gauge future expectations. It is important to note that the costs presented in Section C4 (either at the departmental or aggregate level) are not the costs to be included in revenue requirements.

The O&M Expense for revenue requirements purposes are based on the 2013 Approved O&M Expense, as explained in B6.2.4 of the Application.

112.0 Reference: Exhibit B-1, p. 124

Generation

FBC states that: "In 2012 there was an increase in the number of start/stop requests from BC Hydro to maximize water on the Kootenay River."

112.1 Please identify the number of start/stop requests from BC Hydro in each of the last five years?

Response:

The following table shows the number of unit start/stops request by BC Hydro for the FBC river plants for BC Hydro's optimization of the flows down the Kootenay River.

Year	2008	2009	2010	2011	2012
Unit Start/Stops	5	32	2	34	267

112.2 Are there operational improvements that FBC can suggest to minimize the number of start/stop requests?

Response:

No. Due to the contractual requirements of the Canal Plant Agreement, BC Hydro has the right to dispatch the Kootenay River flows as they choose. However, BC Hydro has agreed that BC Hydro will provide operating instructions to FortisBC for Plants 1 – 4 as though all dispatch costs and benefits accrue to BC Hydro.

113.0 Reference: Exhibit B-1, pp. 122-125

Business Drivers, Generation

FBC states "Annual variation in O&M non-labour is generally attributable to scope of work for non-routine work." (Exhibit B-1, p. 123)

113.1 Provide a description and examples of O&M non-labour generally attributable to scope of work for non-routine work.

Response:

An example of a non-routine task would be the Dam Safety Reviews that are a regulatory requirement. This type of work is completed by engineering consultants. Other non-routine tasks such as roof repairs are generally completed by contractors. Runner welds and related types of work are generally completed using in-house resources.

113.1.1 Please explain why this non-routine work (such as runner weld repairs) is included in the formula since their expenditure cycle of seven years exceeds the PBR term of five years.

Response:

It is important to note that the term "non-routine work" as referenced in the question relates to work performed on a particular unit or piece of equipment. Such work is considered "non-routine" only to the extent that it is non-cyclical.

Runner welds are unit related costs and generally occur on a 2, 5 or a 10-year basis depending on the condition of the runner. Other non-routine tasks can occur with a frequency of 3, 5, 10, 15 year intervals. The frequency of such task may also vary based on annual inspections.

The net effect of such work is that the multiple tasks (with differing frequencies) as performed on multiple units and pieces of equipment results in a more levelized expenditure profile than may be suggested by the term "non-routine". These expenditures are averaged or levelized to an annual value over a long term period such as 15 to 20 years, with this levelized annual value then included as part of the annual expenditures for the PBR term.

113.1.2 Please provide an estimate of the actual, approved, projected, base, and forecasted expenditures for non-routine work from 2010 through to 2018 in table format similar to Tables C4-4 and C4-5.

Response:

The actual and estimated expenditures for non-routine work for 2010-2018 are as follows:

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection
Labour	34	93	51	69	68
Non-Labour	32	118	95	122	74
Total Non-Routine O&M	66	211	146	191	142

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Labour	373	384	395	407	419
Non-Labour	165	169	173	177	182
Total Non-Routine O&M	538	553	568	584	601

113.2 Please explain why regulatory requirements for Dam Safety (p. 122), WorksafeBC requirements (p. 123), and all Mandatory Reliability work are not exogenous expenditures.

Response:

The Company has an obligation to meet all existing regulatory requirements as part of its mandate to provide safe and reliable service to customers. As such, expenditures to meet the existing regulatory requirements for Dam Safety, WorkSafeBC requirements and MRS are already included in the base O&M and capital numbers as part of the PBR Plan. Exogenous factors driving incremental expenditures, or Z-Factors, would apply to any new requirements determined by external regulatory and governmental authorities, and not within FBC management control.

113.3 Please discuss how the ratio $\left(\frac{AC_t}{AC_{t-1}}\right)$ is suitable for forecasting generation operation and maintenance expense of physical assets since FBC's generation has a constant capacity with little opportunity for growth.

Response:

While this may not be the best choice for one set of costs as a measure of how growth impacts O&M, it represents the best overall measure of the growth impact on system costs. As such the growth impact factor is not based on any narrowly defined set of costs but rather applies to all costs associated with O&M. Using separate forecasts of costs based on different cost drivers or to adopt the use of multiple forecast test years as the basis for estimating the I-X values would not be transparent and the process would depart from the basic principle that PBR provide competitive like incentives for the utility. Using a single factor for all O&M is consistent with the fundamental principles outlined for the PBR Plan.

114.0 Reference: Exhibit B-1, p. 127

Operations

FBC states that: "Brushing is a significant component of transmission and distribution line maintenance expenditures."

114.1 To what extent will the increased line clearing activities related to the pine beetle kill over the past 3 years lead to reduced vegetation management expenses in the proposed PBR period?

Response:

FBC considers a free from hazards vegetation management objective as a balanced approach weighing safety and reliability risks with costs and other non-financial considerations. When tree related outages are viewed in conjunction with reliability and the current status of forest health information, FBC believes that the increased line clearing activities related to the pine beetle kill over the past 3 years will have neither a positive or negative effect on the vegetation management expenses during the proposed PBR period as further detailed below.

Trees falling from outside FBC rights-of-way remain a significant contributor to the overall number of outages experienced on FBC transmission and distribution infrastructure.

Year	Percent of Outages caused by "Tree Falling"
2010	23.78%
2011	18.69%
2012	36.93%
YTD 2013 (July)	40.27%

The 2012 Overview of Forest Health Conditions in Southern B.C. published by the Ministry of Forests, Lands and Natural Resources notes the following with respect to forest health conditions in FBC's service territory:

The Okanagan Timber Supply Area:

- The area of Mountain Pine Beetle red attack has remained nearly unchanged from 2011 levels.
- Western Spruce Budworm, (another major contributor to tree mortality) infestations has expanded.

The Boundary Timber Supply Area:

- The Mountain Pine Beetle populations continue to expand with affected areas up over 40% and Western Spruce Budworm populations remaining high with severely defoliated areas increasing fivefold.

The Kootenay Lake Timber Supply Area:

- Overall Mountain Pine Beetle activity has declined with slight increases in the south east portion (Yahk/Creston area) and new infestations noted north east of Nelson (both within the FBC service territory). This TSA still has abundant areas of green pine with the potential for MPB populations to build in the future.

Tree related outages remain a significant contributor to the overall number of outages. As forest health conditions, which contribute to tree mortality, are not forecast to change substantially in the foreseeable future, FBC believes it has reached a rational equilibrium with vegetation management which balances safety, reliability, other non-financial considerations and costs.

115.0 Reference: Exhibit B-1, p. 128 & Table C4-7

Operations

Table C4-7 provides details of Operations O&M costs since 2010.

115.1 Please expand Table C4-7 to include Actual and Approved costs from 2008.

<u>Response:</u>

Please refer to the table provided in the response to BCUC IR 1.115.2.

115.2 Please provide a similar Table showing Actual and Approved Operations O&M costs/customer since 2008?

<u>Response:</u>

Table C4-7 has been expanded to include data back to 2008 with customer count and O&M per customer.

Operations O&M Review ($ Thousands)

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 8,579	$ 8,896	$ 8,668	$ 9,532	$ 10,162	$ 10,060	$ 10,812	$ 10,794	$ 11,564
Non-Labour	6,345	6,161	6,223	9,072	9,758	9,670	10,004	10,144	10,196
Total O&M	**$ 14,924**	**$ 15,057**	**$ 14,892**	**$ 18,604**	**$ 19,920**	**$ 19,730**	**$ 20,816**	**$ 20,938**	**$ 21,760**
Average Customer	**108,722**	**110,286**	**111,552**	**112,756**	**113,588**	**113,587**	**124,581**	**121,566**	**121,566**
O&M per Customer	**$ 137**	**$ 137**	**$ 133**	**$ 165**	**$ 175**	**$ 174**	**$ 167**	**$ 172**	**$ 179**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not allocate O&M Expense by department.

115.3 Costs have risen by 46 percent over the three year period from 2010 Actual to 2013 Base. Even after accounting for Order G-195-10, the costs rise by 21 percent. Why?

Response:

The 2013 Base O&M costs include $822 thousand of adjustments due to pension, OPEB and PST costs which are considered non-controllable; this is described further in Sections C4.3.1 and B6.2.4 of the Application. On this basis, FBC considers the appropriate like-for-like comparison to be between the 2010 Actual and 2013 Projection figures. Further, as noted in the question, approximately $3.78 million of certain capital expenditures were reclassified as O&M costs in December 2010 as a result of Order G-195-10. After accounting for these factors, the actual difference between the 2013 and 2010 costs is approximately $2.266 million; this corresponds to an increase of approximately 15 percent over the three year period.

This increase results from a number of factors:

- Labour cost increases;
- Increased costs to enhance the Power Line Technician (PLT) apprenticeship program to attract and retain sufficient PLTs;
- Increased substation maintenance expenditures primarily driven by requirements to maintain new power system infrastructure; and
- Increased vegetation management costs associated with cyclical brushing and pine-beetle hazard removal activities.

116.0 Reference: Exhibit B-1, pp. 126-127, p. 141

Operations Business Drivers

116.1 For each of the business drivers listed below, please discuss how the ratio $\left(\frac{AC_t}{AC_{t-1}}\right)$ is suitable to forecast the operation and maintenance expense of physical assets:

- Resourcing,
- Line Maintenance
- Vegetation Management
- Substation Maintenance,
- Teck Facility Charge,
- Brilliant Terminal Station,
- IS staffing levels.

<u>Response:</u>

The business drivers listed above starting with Resourcing down to Brilliant Terminal Station are from the Operations Department whose activities are related to the Transmission and Distribution functions of the utility. In the Company's COSA studies the costs for Transmission are classified as Demand Related; and for Distribution the costs are classified as Demand and Customer related. Some costs such as Meters are more directly related to the number of customers being served. For those costs that are classified as demand related these are related to the **customers'** peak demand requirements and are tied to supporting the capacity requirements to deliver the instantaneous power needed. See also the response to CEC IR 1.26.1 and to BCUC 1.27.1.5.

The inclusion of the ratio AC_t / AC_{t-1} is fundamental to including the number of customers that do affect the cost incurrence to meet peak capacity requirement and direct customer related costs.

The IS department provides support to the whole Company and as such the department's O&M costs (both labour and non-labour) are derived from the demand from other departments. The demand for IS are derived from what is required for the ongoing operation of the Company. As such in the embedded COSA studies the IS general costs has been allocated based on labour ratios to the various functions and has been classified as demand (capacity related) and customer-related in the manner those functional physical assets have been classified; all of which is directly or indirectly related to the number customers and the demand they place on the system.

117.0 Reference: Exhibit B-1, p. 129

Operations Summary

FBC states "Any additional cost pressures, including changes in the scope of Operations activities or inflationary increases above those currently forecast will drive incremental costs that the Company will need to offset with productivity realizations."

117.1 Please provide descriptions of foreseen additional cost pressures that may occur between 2014 and 2018.

Response:

FBC faces additional cost pressures related to ongoing market competition for skilled workers including power line technicians, protection and control technologists, power dispatchers and other skilled trades.

117.1.1 Please discuss FBC's proposed mitigation for these additional cost pressures that may occur.

Response:

FBC proposed mitigation for this additional cost pressure includes maintaining relationships with utility contractors, as well as continuation of internal development and training programs and apprenticeships to support the skilled trades for which FBC faces ongoing market competition.

118.0 Reference: Exhibit B-1, pp. 113, 129-133

Customer Service

"Actual inbound call volume for 2012 was higher [than] the 3 year average…The Trail Contact Centre received a total of 188,630 inbound calls during 2012. Large outages in July and October are partially responsible for the call spikes…A number of factors have contributed to generally higher call volume in 2012 as compared to the three-year average such as an increased number of customers, LiveSmart calls, rate increases, rebate programs, and the new Residential Conservation Rate have also impacted call volumes." (p. 129-130)

With respect to bad debt expense, FBC submits that "…Management may also take into account improvements to Collections practices and forecast economic conditions and, based on these, make some manual adjustments." (p. 131)

"Customer service has been able to keep O&M cost increases low (in fact lower than the 2013 approved amount, which was itself reduced by $100 thousand from the amount requested by the Company)…" (p. 132)

118.1 Please recreate Table C4-9 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$3,783	$4,029	$ 4,241	$4,122	$ 4,311	$ 3,788	$4,111	$ 4,002
Non-Labour	1,646	1,673	1,841	2,050	1,876	2,006	2,021	2,061
Pension and OPEB	546	696	542	594	519	881	891	850
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	835	835	835	663
Total O&M	**$5,975**	**$6,398**	**$ 6,624**	**$6,766**	**$ 7,541**	**$ 7,510**	**$7,858**	**$ 7,576**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not allocate O&M Expense by department.

118.2 Given that the actual inbound call volume at the Contact Center was "higher [than] the 3 year average," please discuss if FBC anticipates a decrease in inbound call volume in 2013. Please discuss why or why not.

Response:

FortisBC anticipates a similar volume of calls in 2013 as compared to 2012. Call volumes for the year have remained high due to the RCR, increased bill estimates due to the labour disruption and several large outages. Volumes are predicted to remain at levels comparable to 2012 through to the end of 2013 due to an increase in collections activity and the potential billing corrections which will occur once meters are being physically read again.

118.2.1 How many inbound calls has the Trail Contact Center received in 2013, to date? What are the projected 2013 inbound calls?

Response:

To the end of July 2013, the Trail Contact Centre has received 110,609 inbound calls. As discussed in the response to BCUC IR 1.118.2, call volumes for 2013 are predicted to be similar to what was experienced in 2012.

118.2.2 Please discuss if any net sustainable savings are projected in 2013 related to inbound call volume at the Trail Contact Center. If yes, please provide the projected amount.

Response:

None of the net sustainable savings projected in 2013 are related to inbound call volumes at the Trail Contact Center.

118.3 Please provide the approved and actual bad debt expense for 2011 and 2012 and the approved and projected bad debt expense for 2013.

Response:

There is no “approved” bad debt expense for 2011 and 2012 as the approved amounts are for customer service costs in aggregate.

Actual bad debt in 2011 was $668 thousand and in 2012 was $699 thousand.

Forecast bad debt for 2013 is $630 thousand.

118.3.1 Please discuss any recent improvements to Collections practices or forecast economic conditions that would warrant an adjustment to the 2013 approved bad debt expense for the purposes of determining 2013 Base.

Response:

The implementation of the Residential Conservation Rate has caused changes to the payment and collections patterns that FBC has traditionally experienced. Some customers have seen significant increases in their winter bills this year over last year. As a result of these unexpected bills, customers are experiencing more difficulty keeping their bills caught up. FBC has increased resources in the area of collections to work with these customers to make arrangements on their overdue balances. In addition, more frequent communication with customers who are overdue has been implemented so that we can signal to the customer the need for payment earlier. This includes more “friendly reminder” calls as soon as a customer with a moderate to large balance becomes overdue at 30 days rather than just at 60 days which is done currently. This will help ensure customers do not get further behind, making it more difficult for them to pay.

At this time, it is not known what the impact of these changes and the Company’s reaction to them will be on the 2013 bad debt expense. However, FBC continues to focus on mitigating the issue with an aim to keep bad debt expenses as low as possible.

118.4 Please explain the variance between the $100 thousand 2013 Customer Service savings referenced on p. 132 of Exhibit B-1 and the $31 thousand

Customer service sustainable savings included in Table C4-2 on p. 113 of Exhibit B-1.

Response:

During 2013, the commission reduced the approved amount of customer service O&M by $100 thousand from the amount requested by the Company. In order to meet this reduction, a number of initiatives were undertaken including:

- Continued promotion of eBilling, reducing postage and printing costs;
- Improved collections processes and reduced write-off period resulting in stable bad debt costs; and
- Improved utilization of the Customer Service Representatives for third party and PowerSense work.

The productivity amount of $31 thousand described in Table C4-2 as "sustainable" are savings that were achieved over and above the initial reduction of $100 thousand which were also considered sustainable savings.

119.0 Reference: Exhibit B-1, pp. 133-135

Communications and External Relations

"The expenditure for 2011 was lower than 2010 by $170 thousand largely due to efficiencies realized in the sharing of resources with similar skill sets across the gas and electric operations. The 2012 expenditure was lower than 2011 by $255 thousand largely due to a vacancy not being filled in 2012 in a timely manner but this vacancy was not sustainable over an extended period of time, and due to higher cross-charges to capital." (p. 135)

The 2012 Approved O&M Expenditure for the Communications and External Relations department is $1,431 thousand.

119.1 Please recreate Table C4-11 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 486	$ 463	$ 479	$ 431	$ 486	$ 402	$ 436	$ 461
Non-Labour	1,083	926	891	751	925	944	959	978
Pension and OPEB	70	80	61	62	58	94	95	86
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 1,639**	**$ 1,469**	**$ 1,431**	**$ 1,244**	**$ 1,469**	**$ 1,440**	**$ 1,490**	**$ 1,525**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

119.2 Please provide the amount of any cost reductions factored into the 2012 and 2013 revenue requirements to reflect the "…efficiencies realized in the sharing of resources with similar skill sets across the gas and electric operations" experienced in 2011. If no cost reductions were factored in, please discuss why not.

Response:

In 2011, there was a temporary period of higher cross-charges to the gas operation to backfill a temporary employee leave achieved by leveraging the resources across the gas and electric operations with similar skill sets. This sharing of resources across the gas and electric operations has enabled the department to manage the increasing workload and associated cost pressures through the 2012/2013 period without increasing staffing levels during this same period. In recent years, the department has been facing increasing demands and workload to meet customer and stakeholder expectations. These include customer education initiatives to support programs such as AMI, RCR and in aiding customers to better understand their rates, bills and energy usage. FBC expects that such initiatives and programs will continue into the five year forecasted period.

119.2.1 Please provide the amount of any variances between approved and actual (projected, in the case of 2013) O&M in 2012 and 2013 related to any additional efficiencies realized related to the sharing of resources.

Response:

Please refer to the response to BCUC IR 1.119.2.

119.3 Please confirm when the vacancy referenced in the preamble to this IR was filled.

Response:

The Communication Advisor vacancy was filled in May 2013.

The department intentionally delayed filling the Communications Advisor vacancy in order to determine if the group could manage without this resource, but was not able to manage the workload, and therefore filled the vacancy in 2013.

119.3.1 Please discuss if there are any sustainable cost savings in 2013 related to the vacancy that was filled. Specifically, please discuss if the incumbent employee was hired at a lower salary.

Response:

The employee was hired at a slightly lower base salary by approximately $5 thousand as compared to the previous incumbent, and these labour savings have been appropriately reflected in the 2013 projection and thereby also reflected in the 2013 base from which the 2014-2018 PBR forecast has been developed.

119.4 Please provide reasons for the variance between the 2012 Approved O&M of $1,431 thousand and the 2012 Actual O&M of $1,244 thousand.

Response:

Please refer to the response to CEC IR 1.59.9.

120.0 Reference: Exhibit B-1, Application, p. 136

Energy Supply O&M

FBC states that the Resource Planning responsibilities include"…the assessment and negotiation of the new or replacement contracted resources such as the power purchase arrangements with BC Hydro, and research and assessment of issues such as regional market regulatory developments and planning reserve margin requirements.

Resource planning activities are on-going; however a key responsibility is the development and implementation of the Company's Long Term Resource Plan in accordance with section 45 of the Utilities Commission Act and the Commission's Resource Planning Guidelines."

120.1 Does FBC agree that the successful completion of the 2012 Resource plan makes it easier to develop the 2nd generation plan for 2016? Have those savings been built into the forecast costs?

<u>Response:</u>

FBC agrees that the development of the 2012 Resource Plan provides a good base from which to prepare the 2016 Resource Plan and is hopeful that the overall costs for preparation, filing and regulatory review of the next plan will be lower. However, the resource plan must meet the requirements under Section 44.1 of the UCA, and be consistent with the Commission's resource planning guidelines[18]. As energy markets and BC energy policy are continuously changing, FortisBC will be required to update the regulatory framework, the market assessment, the load forecasts, the market price curve, and its resource options report.

The 2016 Resource Plan must also comply with the direction given by the Commission in its determinations regarding the 2012 Resource Plan as follows:

"The Commission Panel agrees that portfolio analysis is a "best practice" for resource plan analysis. However, the Resource Planning Guidelines do not state that portfolio analysis "must" be done, but that it "should" be done. The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP."[19]

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18 Available at the following link http://www.bcuc.com/Documents/Guidelines/RPGuidelines_12-2003.pdf

19 BCUC Decision, In the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of the 2012 Integrated System Plan, August 15, 2012, Section 7.2.1, page 147

In terms of forecast costs, the Energy Supply O&M forecast only includes those costs related to the 'normal' or on-going resource planning activities that are part of the overall responsibilities of the team. The project costs related to the studies, preparation and regulatory review of Long Term Resource Plan have historically been treated as deferred costs as they are non-routine and provide a multi-year benefit. Those costs will be the subject of future revenue requirement applications.

120.2 With the new PPA with BC Hydro finalized, it appears that FBC has contracted adequate capacity resources for the long term. Does FBC agree that the company's resource planning activities are now simplified? Why or why not?

Response:

As explained in the response to BCUC IR 1.120.1, FBC is hopeful that the preparation and review of the 2016 Resource Plan can be done at a lower cost, however given the requirements FBC does not agree that its resource planning activities are now "simplified". This is particularly true since the 2012 Resource Plan assumed the renewal of the PPA and used the same basic capacity assumptions as exist now, and the integration of WAX CAPA into the FBC resource stack.

The Resource Plan is only one aspect of the Resource Planning Function as explained in the application in Section C, page 136. "These responsibilities include the assessment and negotiation of the new or replacement contracted resources such as the power purchase arrangements with BC Hydro…" In this sense, since the negotiations to finalize the New PPA and associated agreements with BC Hydro were so complex, concluding the agreement is a simplification and resources are freed up to consider other resource planning items in preparation for the 2016 Resource Plan. Ongoing work includes the early stage assessment and development of various future resource options, assessing the PRM requirements and preparing to update the Resource Plan in 2016. FBC will use the 2012 Resource Plan as a solid base to build the 2016 Resource Plan and the most effective way to do that requires ongoing effort. In addition, as further explained in the application in Section C, page 137 and then page 139, the Energy Supply department requires additional support to successfully implement the New PPA and related agreements in order to ensure the new requirements can be managed with minimal impact to costs. Where possible, internal resources are being focused on providing this support.

120.3 Will the limited load growth expectations simplify the load forecasting activity during the proposed PBR period?

Response:

No, the rate of load growth does not affect the level of activity required to prepare the load forecast. To ensure the quality of the load forecast, the Company will perform the necessary forecasting activities up to the expected standard. Any forecast of load growth, regardless of being low or high, is the result of a rigorous process. The Company will prepare a new load forecast each year.

121.0 Reference: Exhibit B-1, Application, p. 136

Energy Supply O&M

FBC states that "Power Supply is also responsible for selling any surpluses that may accumulate during spring runoff and, starting in 2015 when the Waneta Expansion comes into service, Power Supply will be responsible for mitigation activities to manage excess resources that may be available for sale to third parties."

121.1 Does FBC agree that the future resources required to manage surplus sales and Waneta surplus capacity should be similar to past years when the department managed surplus sales and had to acquire added capacity (rather than managing surplus capacity)? Why or why not?

Response:

No, this will not be the case since the volume of transactions required to manage the Waneta surplus capacity will be much higher than what was previously needed to acquire added capacity. FBC expects that it will be an active market participant in all hours of the year either as a buyer of energy or as a seller of surplus capacity. Additionally, FBC's contractual relationship with BC Hydro has become more complex, requiring more detailed oversight to ensure contractual compliance, and to optimize power purchase expense mitigation by taking advantage of all the flexibility provided in the agreements with BC Hydro.

122.0 Reference: Exhibit B-1, Application, p. 137

Energy Supply O&M

FBC states that "As part of the integration and harmonization efforts between the electric and gas utilities, the Company's electric forecast is managed under the purview of the gas utility's Forecasting department staff. However, the labour resources which prepare the load forecast are part of Energy Supply (electric) group."

122.1 Please provide evidence to demonstrate that the total labour cost of load forecasting charged to FBC (FBC costs plus charges from FEI) will be less than when FBC performed its own load forecasting.

Response:

Cost savings to date have primarily been through increased efficiency due to a common management approach to the gas and electric load forecast. Not only has this directly resulted in less electric side resources being used to produce the load forecast, but the quality of the electric forecast has benefited from adapting certain FEI practices such as the Industrial Survey format that resulted in increased response rates. Future savings potential is being explored though the use of a common load forecasting model and increased staff cross-training. As explained in the Application on page 139, lines 10-14, these cost savings are a critical part of the Power Supply group's ability to provide increased levels of support for the Power Supply function within the approved budget.

123.0 Reference: Exhibit B-1, Application, p. 138

Energy Supply O&M

FBC states that: "As a result of these changes to operations, planning and accounting, combined with other developments impacting scheduling non-firm and wind power, FBC has identified the need for additional labour resources in the Power Supply group to fulfill the new requirements, and to maximize its ability to manage and mitigate power purchase expense in order to minimize costs on behalf of customers."

123.1 Please identify the number of new labour positions expected to be added to the Power Supply group in order to accomplish the above noted tasks.

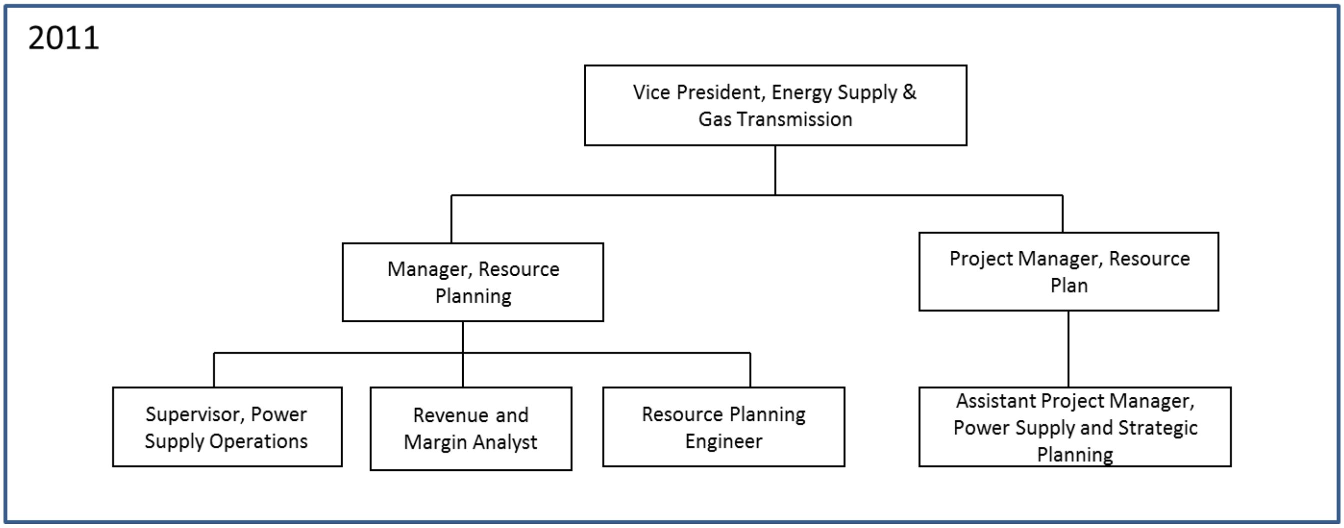
Response:

FBC has forecast that one new FTE is required in the Power Supply group commencing in 2014.

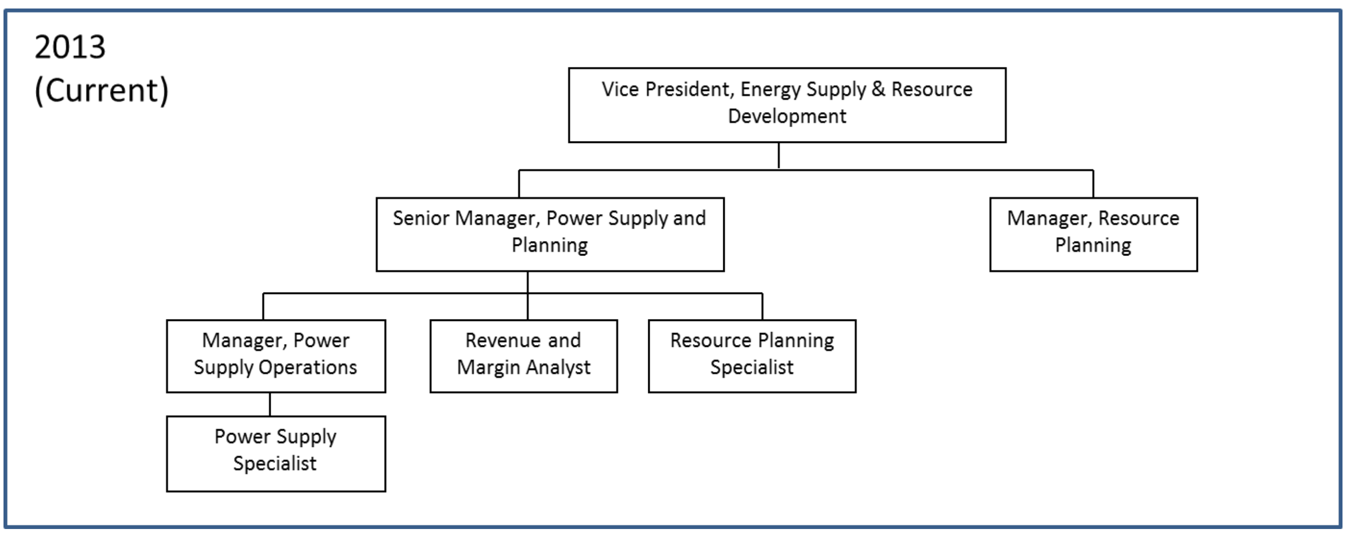
123.2 Please provide the organizational charts for the Power Supply group in 2011, 2013 current, and expected in 2014. Please explain any changes in organization.

Response:

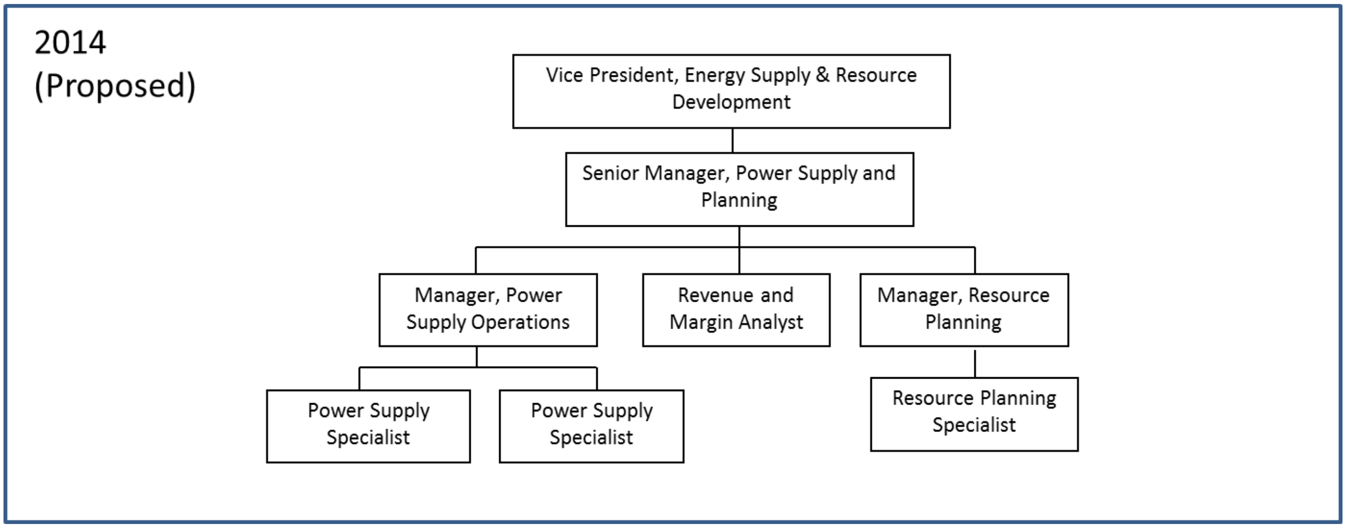
Please see the organizational charts below. Prior to 2011, the responsible executive was VP, Power Supply & Strategic Planning responsible for the electric utility only. Beginning in 2011, the executive position has responsibility for energy supply for both the gas and electric utilities. In 2012, the project manager assistant position was reallocated to support Power Supply operations as Power Supply specialist. The change in titles over the period did not affect the number of positions but are reflective of re-alignment of work responsibilities over the period. The 2014 proposed organization chart shows FBC's expectation of further re-alignment and the addition of a second Power Supply Specialist.



2011
Vice President, Energy Supply & Gas Transmission
Manager, Resource Planning
Project Manager, Resource Plan
Supervisor, Power Supply Operations
Revenue and Margin Analyst
Resource Planning Engineer
Assistant Project Manager, Power Supply and Strategic Planning



2013 (Current)
Vice President, Energy Supply & Resource Development
Senior Manager, Power Supply and Planning
Manager, Resource Planning
Manager, Power Supply Operations
Revenue and Margin Analyst
Resource Planning Specialist
Power Supply Specialist


2014
(Proposed)
Vice President, Energy Supply & Resource Development
Senior Manager, Power Supply and Planning
Manager, Power Supply Operations
Revenue and Margin Analyst
Manager, Resource Planning
Power Supply Specialist
Power Supply Specialist
Resource Planning Specialist

124.0 Reference: Exhibit B-1, Application, p. 138, Table C4-13

Energy Supply O&M

Table C4-13 identifies that O&M costs of the Energy Supply Department have risen from $827,000 in 2010 to $1,178,000 in 2013 Base. FBC provides some commentary on reasons for the increases in costs on pages 138-139.

124.1 Please provide further details including expenditures and staffing information to justify the large increases in this department.

Response:

The level of staffing resources and the O&M budget for the Energy Supply Department is very small compared to the overall requirements of the Company. As a result, any change may have the appearance of being a 'large increase' but this must be kept in context of the Company's overall requirements and the role of the Energy Supply team in managing costs for customers. This team is responsible for the planning, implementation and mitigation of FBC's power supply resources in order to manage power purchase expense costs effectively while maintaining a high level of supply security and reliability. In addition to meeting the Company's Power Supply needs, the Energy Supply group is also responsible for resource planning and load forecasting, including the planning and preparation of the 2016 Resource Plan to meet requirements directed by the Commission.

The changes year over year in the O&M for 2010 and 2011 to the forecast for 2012 and 2013 and related to the Energy Supply Department (then referred to as Power Supply Management Expense) was thoroughly reviewed in FBC's 2012-2013 revenue requirement resulting in the approved budget for 2013 indicated in the referenced Table C4-13 (copied below). The increase in labour expenses was driven by salary adjustments, general wage and benefit inflation, and the timing of the filling of a vacancy in 2010. The increase in Non-Labour expenses was due to a number of factors including increased consulting costs and payment for services provided by FortisBC Energy Inc. In the 2012-2013 RRA Application, FBC also asked for approval to add an additional staff member to meet power supply operational requirements, however that request was specifically denied. This created significant challenges for the Power Supply team, and required re-allocation of resources within the team to meet the most critical gaps. Given the continued increasing complexity of FBC's power supply arrangements, the requirement for additional staff resources is now absolutely necessary and has been included in the 2014 forecast.

Table C4-13: Energy Supply O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 629	$ 631	$ 709	$ 772	$ 732	$ 784
Non-Labour	198	262	277	352	392	394
Total O&M	**$ 827**	**$ 893**	**$ 986**	**$ 1,124**	**$ 1,124**	**$ 1,178**

The O&M costs related to the Energy Supply group should also be put in context of the overall Power Purchase expense which is forecast to increase to $140 million a year by 2018. These are significant expenditures and FBC requires sufficient staff to manage the complex agreements that provide the base of the Company's resources and to meet any remaining needs. To put it another way, the Company purchases about 2,000,000 MWh a year and a reduction in cost of $0.175 per MWh produces savings of $350 thousand or the entire variance between 2010 and 2013 Base. Actual savings have greatly exceeded this amount.

125.0 Reference: Exhibit B-1, pp. 140-143

Information Systems

"Use of internal and external resources are balanced to deliver appropriate levels of support cost effectively." (p. 141)

125.1 Please recreate Table C4-15 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 1,574	$ 1,476	$ 1,476	$ 1,476	$ 1,566	$ 1,417	$ 1,538	$ 1,624
Non-Labour	1,128	1,172	1,177	1,236	1,219	1,242	1,278	1,304
Pension and OPEB	227	255	189	213	189	329	333	303
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 2,929**	**$ 2,903**	**$ 2,841**	**$ 2,925**	**$ 2,974**	**$ 2,988**	**$ 3,149**	**$ 3,231**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

125.2 Please provide an explanation for the variance between the 2012 Approved O&M of $2,841 thousand and the 2012 Actual O&M of $2,925 thousand.

Response:

This increase in 2012 actual O&M was due to the reallocation of an SAP functional resource from the finance area to IS. This transfer was made to optimize responsiveness to system requests by aligning resources, as well as aligning training and development for those resources under common supervision. $84 thousand was transferred from the Finance operating budget to IS operating budget, which makes up the difference between $2.841 million approved and $2.925 million actual costs.

125.3 Please provide the approved and actual (projected, in the case of 2013) cost of external resources for each of 2010, 2011, 2012 and 2013.

Response:

Annual costs for external resources are not specifically approved. There are no specific external resources associated with supporting the operating environment. External resources that would be involved in the support of the operating environment are included in annual maintenance costs for products and are not identified separately in service contracts. External resources are generally associated with capital initiatives. However, individual resource costs are not identified, but instead included in total consulting costs for projects.

All consulting costs are for capital work for the years requested. The following table has the actual consulting costs for 2010, 2011 and 2012, and the projected costs for 2013 broken down by portfolio area:

Project Portfolio	2010	2011	2012	2013 Projection
Desktop & Infrastructure Sustainment	$38,000	$280,000	$31,000	$31,000
Application Sustainment	$35,000	$129,000	$86,000	$30,000
Application Enhancement	$410,000	$440,000	$363,000	$300,000
Business Technology Transformation	$185,000	$255,000	$179,000	$500,000
Total	**$668,000**	**$1,104,000**	**$659,000**	**$861,000**

125.3.1 For each of 2012 and 2013, please provide a detailed explanation of the services that external resources were used for.

Response:

Please refer to the response to BCUC IR 1.125.3. Annual costs by project portfolio area depend on the type of work in the portfolio. Enhancement and transformational portfolios generally require more consulting resources to deliver new functionality or products, as was the case in 2012 and 2013. The majority of consulting costs in 2013 for Business Technology Transformation was the implementation of the new Demand Side Management tracking software. The Application Enhancement consulting costs in 2012 and 2013 were primarily for developers on enterprise system (SAP, CIS, AM/FM) enhancements.

125.3.2 For 2014, please discuss the services that FBC anticipates external resources will be used for.

Response:

Please refer to the responses to BCUC IRs 1.125.3 and 1.125.3.1. As in previous years, external resources are engaged primarily for project work in the enhancement and transformational portfolios. As explained in the response to BCUC IR 1.125.3, external resources are included in annual service agreements that support operating and sustainment activities and not specifically identified. This strategy is intended to optimize internal resources by focusing them on the support and operation of FBC systems.

126.0 Reference: Exhibit B-1, p. 143

Engineering Services and Project Management

FBC states "The Mandatory Reliability Standards department is responsible for ensuring corporate compliance with the BC Mandatory Reliability Standards. On-going effort is required to ensure auditable compliance with all applicable standards and to evaluate the impacts of and implement changes to existing and new standards as well as processes and procedures (internal and external) to support the MRS program in British Columbia."

126.1 It appears the MRS costs are included as a cost driver within several business groups, please explain why.

Response:

The incremental costs associated with MRS are captured in the MRS O&M expenditures as detailed in Table C4-20. The resources to achieve and maintain compliance with MRS are drawn from a variety of business groups.

127.0 Reference: Exhibit B-1, p. 145 & Table C4-17

Engineering Services and Project Management

Table C4-17 provides details of costs for Engineering Services and Project Management from 2010.

127.1 Please expand Table C4-17 to include Actual and Approved costs from 2008.

Response:

Table C4-17 has been extended to include data back to 2007.

Engineering Services and Project Management O&M Review ($ Thousands)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Approved	2013 Projection	2013 Base
Labour	$ 651	$ 823	$ 823	$ 928	$ 1,789	$ 1,951	$ 2,045	$ 2,127	$ 1,974	$ 2,964
Non-Labour	322	361	320	314	574	664	656	664	848	903
Total O&M	**$ 973**	**$ 1,184**	**$ 1,143**	**$ 1,242**	**$ 2,363**	**$ 2,615**	**$ 2,701**	**$ 2,791**	**$ 2,822**	**$ 3,867**

127.2 Costs have risen by 311 percent over the three year period from 2010 Actual to 2013 Base. Even after deducting the MRS impact, costs have risen by 39 percent. How can this trend provide a fair basis to establish a multi-year PBR cost base?

Response:

The 2013 Base value is derived from the 2013 Approved O&M (subject to certain adjustments), not from historical trends. FBC has justified the O&M requirement for this business area in previous regulatory processes and these increases have been approved by the Commission.

128.0 Reference: Exhibit B-1, p. 145 & Table C4-18

Engineering Services and Project Management

Table C4-18 provides details of costs for Engineering Services and Project Management MRS from 2010.

128.1 Does FBC anticipate that the BCUC inquiry into potential adjustments for the BC MRS Program will lead to cost reductions in the future? Why?

Response:

At this time, it is unclear as to what the results of the BCUC inquiry may be. The current draft of information does not appear to offer any opportunities for reductions and may even lead to higher costs in the future.

128.2 Why did Tables C4-17 & 18 not include cost reductions for FBC no longer being subject to WECC voluntary reliability compliance? What were those WECC related costs to FBC in 2010? Why are they so much higher in 2013 when most of the standards are the same as WECC in 2010?

Response:

The costs to maintain full and auditable compliance with the BC Mandatory Reliability Standards are incremental to the organization. They are required in addition to the previous effort of best practices. The previously voluntary WECC Reliability Management System (RMS) had limited scope and focused primarily on operational concerns. The costs associated with participation in the RMS were low and were included within previous budgets. This effort was not specifically tracked and cannot be separated from other expenditures in previous years.

As BC's MRS environment continues to evolve, new and amended standards, external processes, and an increasing complexity of reporting requirements necessitate constant oversight and evaluation. Since BCUC order G-67-09 (adoption of 103 standards and the February 12, 2008 NERC Glossary of Terms), the BCUC (through orders G-167-10, G-151-11, G-162-11, G-175-11,R-17-12, R-1-13 and R-11-13) has adopted 11 new standards, 7 replacement standards, 62 revised standards (11 of which were two revisions at once), the August 4, 2011 NERC Glossary of Terms and modification of the Rules of Procedure. Pending approval are 9 revised standards and the December 5, 2012 NERC Glossary of Terms.

Also contributing to increased O&M costs is the completion of the mitigation plans required to achieve initial compliance with standards, which were largely exempt from self-reporting and self-certification while under mitigation.

129.0 Reference: Exhibit B-1, pp. 145-147

Engineering Services and Project Management Review – MRS

"2013 will be the first year in which the Company will not have a significant percentage of the requirements under mitigation, which increases the requirements for '24/7' compliance monitoring." (p. 147)

129.1 Please provide a breakdown of the 2011, 2012 and 2013 approved and actual (projected, in the case of 2013) costs related to MRS only and a detailed description of the activities associated with these costs.

Response:

The following table indicates the approved and actual MRS costs for 2011 to 2013 (projected for 2013). Actual includes the amounts deferred in 2012 and 2013 as approved by Order G-23-13.

	2011	2012	2013
Approved	$0.9M	$1.2M	$1.2M
Actual	$1.0M	$1.5M	$2.1M

FBC's MRS effort is a combination of increased tasks associated with ensuring compliance to the auditable level required as well as a more comprehensive understanding of ensuring compliance. Information obtained from consultants further informs FortisBC's understanding of the magnitude of effort required to maintain compliance. Some of the tasks that need to be performed are:

- Ensure personnel with physical and cyber access to critical assets have proper documentation in place such as criminal record checks, training, and proper authorization. This information is to be verified by the various departments on a quarterly basis;
- Provide training on an annual basis for MRS related activities such as cyber and physical security awareness, compliance awareness, operation of protection systems and operating personnel. Records are to be kept for what training was received and when. Annual review and signoff of the various training programs is also required;
- Conduct ongoing reviews of personnel access lists with physical and cyber access to critical assets. Lists need to be reviewed quarterly and any changes completed within the specific requirement timelines;
- Conduct annual reviews and signoff of procedures, policies and processes related to the requirements identified in the Mandatory Reliability Standards. These include such documents as facility rating methodology, critical asset and cyber asset lists, cyber

security policy, physical security plan, sabotage reporting, risk based assessment methodology for all assets, protection system maintenance program and plans, physical and cyber security maintenance plans, vegetation management program, emergency response plan;

- Test and document software changes/upgrades prior to implementation to ensure that there is no impact on MRS. This would include such tools as antivirus software, software service packs, vendor software upgrades, operating system upgrades, and database platforms on cyber assets. Typically this implementation process is expected in quarterly timeframes;
- Conduct field maintenance on systems identified in the MRS requirements such as protection systems, physical security systems, cyber security systems and electronic security perimeters on a regular basis. Correct any shortfalls identified in testing;
- Ongoing participation in the review of NERC/WECC standards and regional criteria revisions/additions;
- Maintain and submit compliance records and related documentation for compliance activities as requested internally or by WECC/BCUC;
- Maintain a framework for compliance records and information repository;
- Document and file telephone conversation recordings, email or other equivalent evidence that can be used to confirm that reporting procedures demonstrating compliance with requirements have been followed (ensure an auditable trail);
- Perform internal investigations for potential utility exposure to new MRS requirements associated with new or modified utility activities, processes, procedures, agreements or contractual arrangements;
- Perform routine checks on processes and procedures to ensure compliance is adhered to. If a gap is found, formalization of the violation, and development of subsequent mitigation plans to be submitted to WECC/BCUC;
- Perform annual internal audits and complete self-certifications; and
- Participate in WECC/BCUC audits.

Since the 2012-13 RRA process, FBC's understanding and interpretation of the effort necessary to meet the requirements of the standards has changed, and indeed increased – not only as a result of the formal audit itself – but also through the Company's participation in user group meetings and through consultation with consultants and other utilities. Successful completion of the tasks previously identified requires more detail and effort, including changes to the expected processes, as well as an increased frequency of review than initially expected.

With respect to historical expenditures, it should be noted that MRS-related activities in 2009 and 2010 included both Capital and Operating components, but since 2010, are increasingly operational in nature. The compliance effort in 2011 for Operating was approximately 12,000 hours. Expenditures for 2012 were primarily for Operating effort, with 22 requirements remaining in mitigation. The Operating hours in 2012 were approximately 15,000. In contrast, 2013 will be the first year in which a majority of the requirements will be out of mitigation and require full and ongoing compliance. Based on acquired experience, the changing standards and processes, the audit results, and the knowledge obtained from user group participation, FortisBC forecasts approximately 20,000 hours of internal labour effort to ensure compliance is maintained going forward.

129.1.1 Please provide the amount of any costs associated with the 2012 BCUC / WECC Audit in July of 2012 included in the actual MRS costs for each of 2011, 2012 and 2013.

Response:

FBC had previously budgeted $75 thousand annually for conducting self-certification, spot audits/checks and participating in BCUC / WECC formal audits; a specific allowance for the July 2012 audit was not separated out. This participation was to include FBC audits as well as participation as an observer on audits of other entities. Based on recent experience, FBC has determined that self-certification costs approximately $150 thousand annually and thus has adjusted this forecast cost. The costs of future FBC official audits (with the BCUC / WECC) will be incremental to future budgets.

129.2 Please discuss the reasons for the increase in actual/projected MRS costs from $1,499 thousand in 2012 to $2,088 thousand in 2013.

Response:

Please refer to the response to BCUC IR 1.129.1.

129.3 Does FBC anticipate any sustainable cost savings in 2013 resulting from the fact that it is the first year that a significant percentage of the requirements will not be under mitigation? Please discuss why or why not.

Response:

FortisBC does not anticipate any cost savings as a result of the significant percentage of the requirements not under mitigation. Although some savings may result from not having to action mitigation plans for these standards, FBC expects these savings to be outweighed by costs associated with the now ongoing compliance and reporting for these standards as well as overall MRS program cost pressures.

129.3.1 Please provide the amount of any sustainable cost savings that are expected in 2013.

Response:

FortisBC does not anticipate costs savings under the current BC MRS Program and approved standards. Please also refer to the response to BCUC IR 1.129.3 above.

129.4 Please identify and discuss the major MRS activities that were undertaken in 2013 and those that are expected in 2014.

Response:

The MRS activities undertaken in 2013 are identified in the response to BCUC IR 1.129.1 above. The activities and effort are to continue to ensure compliance is maintained. For 2014, activities will be consistent with 2013 unless changes to the standards, processes, procedures or policies of the BC MRS program occur.

130.0 Reference: Exhibit B-1, p. 147 & Table C4-19

Engineering Services and Project Management

130.1 Please explain the composition of non-labour component of the O&M Forecast shown in Tables C4-19 and C4-20.

Response:

With respect to Table C4-19 (Engineering Services and Project Management non-labour O&M), this component includes:

- Travel and other costs associated with attending technical conferences and training;
- Travel and other costs associated with conducting engineering investigations;
- Membership costs payable to various technical groups and organizations such as CEATI;
- Licensing costs for engineering software tools such as AutoCAD, etc.;
- Professional licensing dues for technical staff; and
- Routine departmental expenses (telephones, stationery, postage, etc.).

With respect to Table C4-20 (Mandatory Reliability Standards non-labour O&M), this component includes costs such as:

- Consultant and contractor costs, including technical support that may be required for any of the standards (particularly the CIP standards due to their complex requirements);
- Travel and other costs associated with attending WECC users group meetings and other conferences and training;
- Travel and other costs for field maintenance/testing to comply with various standards;
- Software licensing costs; and
- Routine departmental expenses (telephones, stationery, postage, etc.).

131.0 Reference: Exhibit B-1, pp. 148-150, p. 271

Operations Support

"…FBC has made reasonable assumptions for the forecast of fuel costs; however, the Company is subject to the risk of budget pressure should the gas price inflation increase above the forecast at any point during the term of the PBR Period." (p. 150)

"The Company is expecting to defer approximately $0.09 million ($0.12 million before tax) of legal costs incurred by the end of 2013 associated with an ongoing litigation matter with a land developer…" (p. 271)

"Operations Support realized cost savings in 2012 and anticipates continued cost savings throughout 2013." (p. 149)

131.1 Please recreate Table C4-21 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$3,037	$2,993	$ 3,097	$2,931	$ 3,133	$ 2,779	$3,015	$ 3,184
Non-Labour	3,152	2,992	3,783	2,754	3,829	3,027	3,042	3,103
Recoveries	(5,633)	(5,186)	(6,053)	(4,868)	(6,087)	(5,247)	(5,453)	(5,591)
Pension and OPEB	438	517	396	423	377	646	654	595
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 993**	**$1,315**	**$ 1,223**	**$1,240**	**$ 1,252**	**$ 1,205**	**$1,258**	**$ 1,291**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

131.2 Please provide the amount of any costs associated with the "ongoing litigation matter with a land developer" included in the actual 2012 or projected actual 2013 Operations Support O&M costs.

Response:

Please refer to the response to BCUC IR 1.131.2.1.

There are no costs included in the actual 2012 or projected 2013 Operations Support O&M costs relating to this matter.

131.2.1 Are any of legal costs associated with the "ongoing litigation matter with a land developer" offset by O&M cost savings achieved in 2012 and those anticipated in 2013? If not, please discuss why not. If yes, please provide the amount.

Response:

None of the legal costs associated with the ongoing litigation matter with a land developer were offset by 2012 O&M savings or those anticipated in 2013 because the majority of the costs with respect to this matter were incurred by the end of 2010. Pursuant to Order G-193-08, the Commission approved the establishment of a deferral account specifically for the purposes of capturing these legal costs.

By way of background and further explanation, we provide a summary of this litigation. In May 2008 Hilltop Sand & Gravel Co. Ltd. ("Hilltop") filed a petition in the Supreme Court of British Columbia that asked the Court to declare that:

(a) FBC's easement over Hilltop's Land did not prevent the Hilltop from constructing and dedicating to the City of Kelowna the road created by Hilltop's proposed subdivision plan or

(b) That FBC's easement be replaced by an easement over a different area of Hilltop's land.

Hilltop wished to develop its land by subdividing and developing the land for sale as single family housing lots. Hilltop claimed that FBC's easement over the land unreasonably impeded Hilltop's ability to develop the land. FBC opposed the petition because a finding in favour of Hilltop would require relocation and redesign of FBC's distribution and transmission corridor and would restrict future expansion of the transmission line.

In addition, FBC believed that if it did not oppose Hilltop's petition, other developers of land over which it held statutory rights of way might apply to the court for the same kinds of orders, which would result in FBC losing its existing rights to future expansion and require FBC to acquire new rights, at considerable expense, when constructing new facilities.

In January 2010 the Supreme Court of British Columbia found in favour of FBC, agreeing that FBC needed to be able to retain its easement rights to be able to expand the electric system in the future. Hilltop filed an appeal of this decision. To date, it has not pursued the appeal.

As a result, FBC believes that the legal costs it incurred in defending this litigation were prudently incurred as FBC would otherwise be forced to incur significant capital costs, some in respect of the Hilltop development, and greater ones in respect of further expansion of the FBC system in areas where existing expansion rights have been lost.

132.0 Reference: Exhibit B-1, pp. 150-153

Facilities

"The 2013 Base has been adjusted for the purchase of the Trail Office building, as approved by Order G-110-12, and the resulting termination of the existing lease." (p. 152)

"The O&M expenses for the Facilities department have been relatively steady with a slight decrease in 2012 and 2013 due to a reduction in labour requirements, lease space and the cyclical nature of the maintenance work." (p. 152)

132.1 Please recreate Table C4-23 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 505	$ 427	$ 435	$ 337	$ 445	$ 342	$ 371	$ 436
Non-Labour	3,122	3,219	3,195	3,210	2,967	2,967	2,074	2,166
Pension and OPEB	73	74	56	49	54	80	81	81
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 3,700**	**$ 3,720**	**$ 3,685**	**$ 3,596**	**$ 3,466**	**$ 3,389**	**$ 2,526**	**$ 2,683**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

132.2 Please provide the approved and actual lease expense related to the Trail office building for 2011 and 2012 and the approved and projected lease expense related to the Trail office building in 2013.

Response:

The approved and actual lease expense for the Trail office building for the years of 2011 and 2012 is provided below.

Trail Office Lease		
	Approved Budget	Actual Budget
2011	1,212,000	1,212,000
2012	1,212,000	1,212,000

FBC has exercised its option to purchase the Trail building. The lease terminates on September 30, 2013. FBC's 2013 approved and projected budget for the Trail lease expense is $909 thousand.

132.2.1 When does the Trail office lease and the associated lease payments terminate?

Response:

The Trail office lease and associated lease payments terminate September 30, 2013.

132.3 Please provide a breakdown of the 2013 sustainable savings of $77 thousand and provide a detailed explanation of the reasons for the savings.

Response:

The 2013 sustainable savings of $77 thousand was created by combining two Facilities positions within FBC and FEI into a single position within FEI. This change has allowed for a reduction in one FTE from FBC offset by the required FEI labour cross charge.

132.4 Please discuss the reasons for the "reduction in labour requirements" experienced in 2012 and 2013.

Response:

The Facilities Department has combined two FTE positions within FBC and FEI into a single FTE position residing within FEI. While this is a reduction in one headcount within FBC, the sustainable savings does not reflect a full FTE cost reduction due to the requirement to cross charge by FEI. In addition, in 2012, Facilities had one FTE partially delegated to the Union Bargaining Committee, as such when the individual was away their salary was paid by the Union. This savings is not sustainable for future years.

133.0 Reference: Exhibit B-1, pp. 153-157

Environment, Health and Safety

133.1 Please recreate Table C4-25 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

<u>Response:</u>

The table below provides the data requested.

	2010 Actual	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projection	2013 Base	2014 Forecast
Labour (Excluding Pension and OPEB)	$ 512	$ 588	$ 652	$ 624	$ 678	$ 673	$ 731	$ 772
Non-Labour	141	178	190	180	193	123	124	127
Pension and OPEB	74	101	83	90	82	157	158	144
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 727**	**$ 867**	**$ 925**	**$ 894**	**$ 953**	**$ 953**	**$ 1,013**	**$ 1,043**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.

134.0 Reference: Exhibit B-1, pp. 157-160, p. 267

Finance and Regulatory Services

134.1 For each of finance services and regulatory services, please recreate Table C4-25 using the following O&M categories: Labour (Excluding Pension and OPEB), Non-Labour, Pension and OPEB, Insurance, and City of Kelowna O&M. Please also include an additional column for 2010, 2011 and 2012 Approved and 2014 Forecast.

Response:

The table below provides the data requested.

Finance Services	**2010 Actual**	**2011 Actual**	**2012 Approved**	**2012 Actual**	**2013 Approved**	**2013 Projection**	**2013 Base**	**2014 Forecast**
Labour (Excluding Pension and OPEB)	$ 1,622	$ 1,733	$ 1,991	$ 1,556	$ 1,940	$ 1,662	$ 1,804	$ 1,905
Non-Labour	654	779	1,029	891	1,059	1,003	1,008	1,028
Pension and OPEB	234	299	254	224	233	387	391	356
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 2,510**	**$ 2,811**	**$ 3,274**	**$ 2,671**	**$ 3,232**	**$ 3,052**	**$ 3,203**	**$ 3,289**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.
Note - Assumption made that reference Table C4-25 should have referenced Table C4-27

Regulatory Services	**2010 Actual**	**2011 Actual**	**2012 Approved**	**2012 Actual**	**2013 Approved**	**2013 Projection**	**2013 Base**	**2014 Forecast**
Labour (Excluding Pension and OPEB)	$ 702	$ 729	$ 779	$ 759	$ 798	$ 622	$ 675	$ 712
Non-Labour	263	216	240	284	145	262	264	269
Pension and OPEB	101	126	99	110	96	144	146	133
Insurance	-	-	-	-	-	-	-	-
City of Kelowna	-	-	-	-	-	-	-	-
Total O&M	**$ 1,066**	**$ 1,071**	**$ 1,118**	**$ 1,153**	**$ 1,039**	**$ 1,028**	**$ 1,085**	**$ 1,114**

Note - FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not approve O&M Expense allocated by department.
Note - Assumption made that reference Table C4-25 should have referenced Table C4-27

134.1.1 For each of 2012 and 2013, please discuss the reasons for any variance between approved and actual (projected, in the case of 2013) O&M related to the Regulatory department.

Response:

The Regulatory department variances for 2012 and 2013 (projected) are as follows:

	2012 Actual	2013 Projected
Actual/Projected	$ 1,153	$ 1,028
Approved	1,118	1,038
Variance	$ 35	$ (10)

The 2012 variance of $35 thousand is primarily attributable to an increase in consulting costs to support regulatory activities and to higher than forecast BCUC levies. The 2013 projected variance of $(10 thousand) is less than one percent lower than the approved value and can not be attributed to any particular cause.

134.2 For each of 2012 and 2013, please discuss the reasons for any variance between approved and actual (projected, in the case of 2013) O&M related to the Finance department.

Response:

The comparison of the Finance department's O&M is as follows:

Finance	2012 Approved	2012 Actual	variance	2013 Approved	2013 Projection	variance
Labour	2,245	$ 1,780	(465)	$ 2,173	$ 2,049	$ (124)
Non-Labour	1,029	$ 891	(137)	$ 1,059	$ 1,003	$ (56)
Total O&M	**$ 3,274**	**$ 2,671**	**$ (603)**	**$ 3,232**	**$ 3,052**	**$ (180)**

2012 actual Finance Labour costs were lower than 2012 approved by approximately $0.5 million primarily due to approximately 2.5 vacant positions during 2012 (explained further in the response to BCUC IR 1.135.4) and the reallocation of one position to the Information Systems department. As described in Section C4, Part 4.14.3 of the 2014-2018 PBR Application, these vacancies arose primarily as a result of employee turnover and the Finance department having difficulty filling vacant positions. The Finance department assesses its resources to meet the evolving business requirements, which contributed to the labour decrease in 2012 as certain vacant positions were subsequently filled only after reviewing the need for the positions and evaluating how best to staff the positions

2012 actual Finance Non-Labour costs are lower than 2012 approved by approximately $0.1 million primarily due to lower external auditor fees than forecast.

2013 projected Finance Labour costs are lower than 2013 approved by approximately $0.1 million due to not staffing a position, resulting in efficiency savings to be carried over into the PBR term. Only after reviewing the need for positions and evaluating how best to staff the positions over the term of the PBR, was one position not filled. To clarify, the 2013 Approved and Projection Finance Labour costs do not include the position that was allocated to the Information Systems department.

2013 projected Non-Labour costs were lower than 2013 approved by approximately $0.1 million primarily due to lower external auditor fees than forecast, partially offset by increases in cross-charges for tax and treasury services performed by FHI.

The aggregate favourable variance between 2013 approved and 2013 projection for Finance O&M of $0.2 million has been included as a sustainable reduction to the base O&M calculation which is used to determine revenue requirements in 2014 through 2018, as shown in Section C4, Table C4-1 of the 2014-2018 PBR Application.

135.0 Reference: Exhibit B-1, p. 157-160

Finance and Regulatory Services

135.1 To what extent is the Finance department aligned with or integrated with FEI? What year?

Response:

While FEI and FBC's Finance departments are not fully aligned or integrated, there has been effort and progress made where it is beneficial from a policy, resource and cost perspective. FEI and FBC Finance departments are still required to account, report and forecast financial information for each separate legal entity and each maintain separate accounting information systems, while adhering to separate collective agreements in place with respective bargaining units, all of which currently limit the degree of integration at this time. However, the FEI and FBC Finance departments are continuing to move towards integration as the sharing of services includes one CFO with oversight over FEI and FBC since the beginning of 2012; tax and treasury services provided by FortisBC Holdings Inc. for FBC, which began in the last half of 2012; property tax services provided by FEI for FBC, since 2008; and oversight of certain accounting functions by FBC for FEI, which began in the last half of 2012.

135.2 To what extent is the Regulatory department aligned with or integrated with FEI? What year?

Response:

Integration of the Regulatory departments of FBC and FEI commenced in 2010 with the appointment of a common executive team. The departments are aligned at the senior management level and administrative levels, and work together closely where commonalities are present, for example the development of the 2014-2018 PBR Plan and the GCOC proceedings. As the two business units are operationally different, the two departments are also engaged in building familiarity with each other's businesses and practices with a view to increasing the degree of regulatory support between businesses that will be possible in future regulatory applications and processes.

"During the period 2010 to 2013 Projection, the Finance and Regulatory department has managed to meet its increasing business requirements while the O&M labour has moderately increased at an average of 2 percent per year. Labour costs temporarily declined in 2012 from 2010 and 2011 levels due to employee turnover and the Finance department having difficulty filling vacant positions." (Exhibit B-1, p. 159)

135.3 Please explain the "increasing business requirements" in the Finance and Regulatory department.

Response:

FBC identified in Section 4.14.2.2 (page 159) of the Application that:

"The resources required by the Regulatory department are driven by the regulatory environment, particularly the number and complexity of rate setting and project approval filings with the Commission. In recent years the complexity of FBC's applications, regulatory processes and compliance requirements has increased. Regulatory processes are typically attracting more interveners, taking longer, and costing more than in previous years. The increased interest and the associated time and cost requirements continue to put pressure on the Company's regulatory and other resources. Although the Company is challenged to maintain the current level of regulatory process and activity, it is not planning to increase personnel…"

FBC's Finance department also explained its "increasing business requirements" under Section 4.14.2.1 on page 158-159 of the Application as follows:

"US GAAP guidance continues to evolve and establish more rules and standards. Regulatory applications and decisions are increasing in number and complexity which require an increase in financial modelling and forecasting, as well as applying the relevant accounting guidance. Accordingly, the Finance department is responsible for the on-going assessment and implementation of accounting guidance and standards. This may result in changes to accounting policy, adjustments to financial statement presentation and note disclosure, as well as changes to the financial reporting and accounting processes. Certain accounting guidance or regulatory decisions may not result in a financial statement or regulatory impact; however, they still require the Finance department to perform extensive research into the facts and circumstances and the preparation of position papers to demonstrate the appropriate application of the accounting guidance for external auditors. Similarly, the outcome of increasingly complex regulatory and business decisions needs to be assessed in accordance with income tax legislation and regulations to ensure that the tax impacts are identified and applied appropriately.

Additional challenges for the Finance department include active involvement in the Company's forecast capital expenditures over the next five years. This will require the Finance department to manage debt financing, either through operating credit facilities or debt offerings, and the managing of budgets, accounting and reporting of capital expenditures. A priority is being responsive to the needs of other departments, ensuring that accurate and timely accounting and financial information is provided to departments to help manage the business."

"The financial complexities arising from accounting guidance and regulatory applications, as documented in the Business Drivers section, require the Finance department to be adequately resourced with a team who have the relevant financial skills and experience."

There are other increasing business requirements not explicitly referred to in the 2014-18 PBR Application, but are representative of the challenges faced by the Finance department since 2010 and are expected to continue or increase during the term of the PBR. These would include, but are not limited to, managing increased complexities around accounting and reporting for employee future benefits (pension and OPEBs), performing more frequent depreciation studies, increased transactions which require appropriate implementation of transfer pricing policy, increased sharing of services among the FortisBC Utilities, assessing and applying the tax implications of increasingly complex regulatory decisions, interpreting and applying the new PST Act, increased scrutiny of regulatory decisions by the external auditors, assessing new power purchase arrangements under the relevant financial instrument accounting guidance, accounting for asset retirement obligations, accounting for leases and increased debt compliance to support the increasing debt used to finance the Company's rate base. All of the above is evidence that the Finance department is facing an increase in regulatory, compliance and accounting requirements as compared to three or four years ago.

135.4 Please discuss the employee turnover in 2012. How many position(s) does this equate to?

Response:

Employee turnover specifically resulted in two positions not being filled during 2012, as well as other lag time between filling other positions, amounting to an estimated total of approximately 2.5 actual vacant positions in 2012, which was the primary cause of the decrease in actual 2012 labour as compared to 2012 approved.

The equivalent of one vacant position, only after reviewing the need for positions and evaluating how best to staff the department, was left vacant for 2013. As a result of the Finance department opting not to fill the 2013 position, there is a savings of approximately $0.1 million compared to the 2013 Approved Finance O&M. This has been carried forward in the calculation of the base O&M calculation used to determine revenue requirements in 2014 through 2018.

135.4.1 Does FBC know why there was difficulty in filling theses vacancies in 2012? Please explain how the state of the economy during 2012 affected FBC's ability to fill these positions?

Response:

FortisBC's perspective on the difficulty in filling Finance vacancies during 2012 was explained in section C, part 4.14.3 on page 159 of the 2014-2018 PBR Application which stated that "the financial complexities arising from accounting guidance and regulatory applications, as documented in the Business Drivers section, require the Finance department to be adequately resourced with a team who have the relevant financial skills and experience". For certain positions, FortisBC was not able to successfully recruit candidates with the relevant rate-regulated accounting skill set and experience required to meet the Finance department's increasing business requirements which are described in the response to BCUC IR 1.135.3.

FBC's Finance department did not necessarily see the state of the economy during 2012 as having an explicit impact, one way or another, on the ability to fill these positions.

135.5 How did FBC manage the vacancies during 2012 and please discuss why this is not sustainable over the long term.

Response:

FortisBC's Finance department managed the 2012 vacant positions primarily by having staff forgo vacation, management working more overtime than normal and through receiving support from FHI for tax services. The combination of increasing business requirements, explained further in the response to BCUC IR 1.135.3, turnover and lack of resources was not sustainable over the long term as it was expected that the accuracy of the accounting and forecasting, the application of accounting guidance, the interpretation of regulatory decisions and the maintenance over internal controls could potentially be compromised, thus increasing financial risk.

135.6 Given that the vacancies in 2012 are not considered "sustainable over the long term" (Exhibit B-1, p. 159), would it be more relevant to look at the 2011 Actuals (that is, prior to the vacancies of 2012) in order to determine the 2013 Base for this department? Why or why not?

Response:

No, the 2013 Finance department O&M projection is the most relevant and accurate forecast to use in establishing 2013 Base O&M as it contemplates the appropriate costs to meet the increasing business requirements over the term of the PBR. 2011 Finance department O&M actuals are less relevant for establishing 2013 Base O&M as it does not consider inflationary drivers, sharing of financial services with FEI/FHI, increases in external audit fees, increases in rating agency fees and increases in trustee agency fees, partially offset by the reduction of a vacant position in 2013. In addition, 2011 actual O&M considered lower actuarial fees as compared to 2013 to determine pension and OPEB expenses since a September 30 measurement date could be utilized under Canadian GAAP. For 2013 Projection, actuarial estimates are required for pension and OPEB expenses in forecasting revenue requirements for the subsequent year and then again at the December 31 measurement date to determine actuals. This change in measurement date is required under both IFRS and US GAAP for 2013 and onwards since pre-changeover Canadian GAAP utilized in 2011 no longer exists as a financial reporting option. Even with the various cost increases from 2011 actuals, the 2013 Projected Finance O&M used to establish the 2013 Base O&M for the 2014-18 PBR Application, is still approximately $0.2 million less than 2013 Approved Finance O&M, thus demonstrating sustainable savings.

135.7 Table C4-2 shows that there are $191 thousand of "sustainable savings" in this department for 2013 and beyond. Please explain to what extent these savings are related to the vacancies of 2012?

Response:

Please refer to the response to BCUC IR 1.135.4.

FBC states "Regulatory requirements are expected to remain high and Finance service requirements are expected to continue to change and increase. The department will try to address this challenge by reviewing and streamlining existing work processes and capitalizing on integration and resource sharing opportunities, if any, between the Electric and Gas Finance departments." (Exhibit B-1, p. 160)

135.8 Please explain whether any integration opportunities were explored in 2012? If so, please discuss and quantify where possible. If no opportunities were explored in 2012, why not?

Response:

Integration opportunities were explored in the last half of 2012 as explained in the responses to BCUC IRs 1.135.1 and 1.135.2.

During 2012, there was an incremental approximately $20 thousand allocated for tax and treasury services from FHI to FBC's Finance department, offset by an incremental approximately $40 thousand allocated from FBC to FEI for oversight of certain accounting functions.

"The increase in non-labour from 2010 to 2013 is due in part to incremental actuarial and accounting services, as well as taxation, treasury and cash management support provided by FHI. Other contributors to non-labour increases are related to external audit fees, rating agency fees, debt trustee fees, various filing fees and miscellaneous support costs." (Exhibit B-1, p. 160)

135.9 The increase in non labour expenses in this department has nearly increased 30 percent between 2010 and 2013. Please confirm that the services provided by FHI are allocated to both FEI and FBC.

Response:

Confirmed. FHI performs services and allocates costs to both FEI and FBC. For 2012 and 2013, only select treasury and tax services related costs were allocated from FHI to FBC's Finance department. FHI provided other services to FBC for internal audit, legal and other governance which were not included in the FBC Finance department O&M for 2012 and 2013.

Factors that increased FBC's Finance department non-labour O&M are described in the response to BCUC IR 1.135.6.

135.10 Please explain how the services provided by FHI are different than the services performed by Fortis Inc. in the Corporate O&M department, which includes treasury, taxation, executive, financial reporting, etc.

Response:

FHI is providing services to FBC's Finance department, which include daily cash management, review of various tax returns and addressing income tax and commodity tax queries, all of which are reflected in the 2013 FBC Finance department's projected non-labour O&M.

The treasury, taxation, executive, financial reporting and other services identified under Section C4, part 4.17.1.1 - Fortis Inc. Corporate Services Fee on page 167-168 of the 2014-2018 PBR Application are performed by Fortis Inc. and are more strategic, corporate governance by nature thereby providing Fortis Inc. with the ability to access capital markets and furnish equity funding for FortisBC. These Fortis Inc. corporate services are recognized in Corporate O&M and have been approved in rates since Fortis Inc. acquired FortisBC in 2004. These Fortis Inc. corporate services are complementary and extend beyond the daily, transactional treasury and tax services performed by FHI for FortisBC's Finance department beginning in 2012.

135.10.1 Are FHI and Fortis Inc. the same entity?

Response:

No. FHI is FortisBC Holdings Inc., the parent company of FortisBC Energy Inc. As indicated in the current organization chart included in Appendix C4 of the 2014-2018 PBR Application, FHI is a wholly owned subsidiary of Fortis Inc.

136.0 Reference: Exhibit B-1, p. 160-164

Human Resources

FBC states that "HR has 12 Full Time Equivalent (FTE) employees, a reduction of approximately 14 percent from previous years." (Exhibit B-1, p. 161)

136.1 Please clarify the number of FTEs in this department over 2010-2013. Which years is the FTE reduction referring to?

Response:

The number of FTEs in FBC's HR department from 2010-2013 is shown in the table below.

Number of FTEs in FBC's HR Department from 2010-2013

2010	2011	2012	2013
14	11	14	11

The FTE reduction is referring to 2013 over 2012. (It should be noted that the preamble was based on FTE information available as of January 1, 2013, when the HR department of FBC had 12 FTEs, which accounts for the 14% reduction over 14 FTEs in 2012. Using present data, the reduction is approximately 21% from the previous year.)

136.2 Please discuss whether the reduction in FTE's is related to the integration with FEI? Otherwise, what is the reasoning for the 14 percent reduction?

Response:

The reduction in FTEs from 2012 to 2013 is related to the integration with FEI. The reduction in FTE's is a direct result of integrating the compensation, pension and benefits groups within HR. Efficiencies were realized by having these services provided by FEI employees, who cross charge time to FBC as appropriate.

FBC states "The shifting of resources from labour to non-labour O&M in 2012 and 2013 are as a result of electric HR labour cross charging to gas and the receiving of gas labour costs in electric non labour accounts." (p. 162)

136.3 Please explain the cross-charges between FEI and FBC. Is this a result of the integration efforts?

Response:

The cross-charges between FEI and FBC are a result of integration efforts. Electric HR labour cross charges to gas for services provided to support the gas utility (for example, disability management services). Likewise, gas labour costs are received in electric labour accounts when gas HR labour provides services to support the electric utility (for example, employee development, and benefits and compensation administration).

Please see the table below for the amount of cross-charges from FEI to FBC (and vice versa) for 2012 and 2013 year-to-date.

	Gas Labour Costs Received in Electric (in $000's)	Electric Labour Costs Received in Gas (in $000's)	Net Effect
2012	**$349**	**$192**	**$157**
2013	**$83**	**$154**	**($71)**

Year-to-date for 2013, the net effect shows that electric has cross-charged more to gas than vice versa, which is the converse of 2012. This can be explained in part by an additional electric HR employee performing work for gas in 2013 (who did not cross charge in 2012), and also by the fact that the net effect for 2013 is being measured at a point in time. FBC's expectations are that by year-end, the net effect will be more balanced.

"Integrated employee programs will enable the movement of staff throughout the company and enable operational flexibility through mobility of the workforce." (p. 163)

136.4 Please explain how the "movement" of employees actually take effect? Are these integrated department employees from FHI (Fortis Inc) or are they still considered employees of FEI/FBC and cross charge their services?

Response:

The movement of employees throughout the Company has taken effect in different ways, including:

1. Expanding the scope of an employee's role in one utility to have responsibilities within the other utility; and
2. Transferring an employee from one utility to a different role within the other utility.

Where the scope of an employee's role has expanded such that the employee has responsibilities within both utilities, the employee will remain an employee of one utility, and will cross charge their services to the other, as appropriate.

Where an employee transfers from one utility to a different role within the other utility and has responsibilities for one utility only, they will cease being an employee of the first utility, and will become an employee of the other utility, for which they are now performing work.

There are employees from FHI who provide services to FBC. These employees cross charge their services to FBC, as appropriate.

The integration of employee programs such as M&E compensation, benefits and performance management allows both of these types of employee "movement" to take place by standardizing programs and practices across the utilities and eliminating inequities between the companies.

Note: FHI is FortisBC Holdings Inc., and not Fortis Inc. FHI is a wholly-owned subsidiary of Fortis Inc.

136.5 Are any of these integration employees charged through an allocation method?

Response:

Please refer to the response to BCUC IR 1.136.4. Integration employees are not charged through an allocation method. Any employee of either FBC or FEI who has responsibilities within the other utility cross charges time for their services directly to the other utility by recording that time on their timesheets.

"In 2012, the employee development, talent sourcing, labour relations, compensation administration, pension and benefits administration and corporate HR functions were integrated and aligned between gas and electric utilities." (Exhibit B-1, p. 162-163)

In the attempt to understand the integration efforts, Commission staff summarizes the labour and non labour costs in this department, based on the data filed in Table C4-29. The 2013 data is used to compare with the actual results of 2011 and 2011, prior to the integration with FEI:

in ('000)	2013 Projection over 2011 Actual	2013 Projection over 2010 Actual
Labour	<$89>	<$181>
Non Labour	+$216	+$417
Net Effect	+$127	+$236

136.6 Please confirm that the savings due to integration (between FBC and FEI) are shown in the reduction to the labour charges, while the cross charges due integration are shown in the non-labour expenses.

Response:

The reduction in labour charges from 2013 Projection over 2011 Actual and 2013 Projection over 2010 Actual is a reflection of labour savings through cross charges to FEI experienced by FBC due to integration.

The cross charges resulting from integration are shown in the non-labour expenses. However, non-labour expenses also includes other costs such as pension consulting costs, support for community giving programs, travel expenses, etc.

Please refer to response to BCUC IR 1.136.3 for a summary of cross-charges to the non-labour expenses for 2012 and 2013.

136.7 The above table appears to indicate there are direct savings from labour expenses after integration. However, cross charges from FEI have increased to levels which have wiped out those labour savings. The net effect of integration has actually increased total expenditures in this department. Does FBC agree with this observation? Please discuss.

Response:

FBC's HR department has experienced direct savings from labour expenses after integration. This is due to a reduction in HR headcount and the corresponding alignment of responsibilities within HR across the gas and electric utilities.

However, as noted in response to BCUC IR 1.136.6, cross charges from FEI make up only a portion of non-labour expenses. For example, in 2012 cross charges from FEI made up approximately 45% of non-labour expenses, while in 2013, cross charges from FEI have made up only 11% of projected annual non-labour expenses to date. Therefore, it is inaccurate to suggest that cross charges from FEI have increased to levels which have wiped out those labour savings. Other costs have been absorbed in non-labour that if not for the savings would have resulted in increased operating costs in 2013.

Overall, FBC believes that the HR department has been able to provide additional support and programs without adding additional resources. Please refer to the response to BCUC IR 1.96.3 for examples of these activities.

FBC states that "Alignment of the employee programs achieved efficiencies in administration...In 2013, 69 jobs were filled as of May 1, 2013, an increase of 39 percent over the same time period in 2012." (Exhibit B-1, p. 163)

136.8 Please confirm that FBC is using 'number of jobs filled' as a measure of efficiency.

Response:

In the context of the preamble, FBC used the "number of jobs filled" to demonstrate efficiencies gained through integration of the talent sourcing function. Essentially, FBC was able to fill more vacancies with no increase to HR headcount.

136.9 To what degree does the improved state of the economy in 2013 versus 2012 contribute to the expedient filling of these positions, as opposed to the efficiencies in administration?

Response:

Certain technical and professional positions, particularly in the engineering field, were more difficult to fill in 2013 compared to 2012. Due to the nature of the labour market, employees already in demand for their particular qualifications had many available employment options. Additional efforts were required for recruitment, the time it takes to fill roles increased, and how roles were filled was reconsidered.

137.0 Reference: Exhibit B-1, pp. 163

Human Resources

"Legal costs associated with the contract negotiations with COPE and IBEW are being offset by O&M savings through efficiencies."

137.1 Please provide an update on the status of the contract negotiations with COPE and IBEW.

Response:

The COPE collective agreement expires on December 31, 2013. Under provincial labour legislation, notice to commence collective bargaining may be given anytime within the four months prior to a collective agreement expiring. Negotiations will likely commence in the fourth quarter of 2013.

The COPE Customer Service collective agreement expires on March 31, 2014. Negotiations will likely commence in the first quarter of 2014.

The IBEW collective agreement expired on January 31, 2013. FBC and the IBEW have been in negotiations since January 7, 2013. An agreement has not yet been reached.

137.2 Please provide a breakdown of the actual 2012 and forecast 2013 costs incurred related to the contract negotiations with COPE and IBEW, and an explanation for the activities associated with these costs (i.e. legal costs, overtime due to strike activity).

Response:

Legal expenses incurred as a result of contract negotiations are set out in the following table.

Legal Expenses Related to Contract Negotiations with COPE and IBEW

YEAR	COPE Negotiations	IBEW Negotiations
2012	$50,193	$0
2013 YTD	$0	$212,675

Additional legal expenses beyond those indicated above are contingent upon the requirement for further legal support.

138.0 Reference: Exhibit B-1, p. 160-164; Exhibit A2-1, FBC Five Year Workforce Plan

Five Year Workforce Plan

FBC states “Efficiencies in HR service delivery and in the leveraging of e-learning technology have been used to offset the costs of increased activities in workforce planning and targeted recruitment and development of staff as part of the Company’s execution on its five year workforce plan.” (Exhibit B-1, p. 164)

138.1 Please confirm that the five year workforce plan referenced above is the FBC compliance filing dated November 30, 2012, and filed as Exhibit A2-1 in this proceeding.

Response:

Confirmed.

139.0 Reference: Exhibit B-1, p. 118

Demographics

"Between 2013 and 2018, 552 employees, or roughly 24 percent of the total employee population of the combined gas and electric utilities are eligible to retire with unreduced pensions. When including the 357 employees also eligible to retire with reduced pensions, the total number of employees eligible to retire (unreduced and reduced pensions) increases to 909 or 39 percent of the current workforce… Between 2008 and 2012, only 14 percent of those eligible to retire with a reduced or unreduced pension exercised their retirement option."

139.1 Please provide the number of FBC employees that are expected to retire with unreduced pensions between 2013 and 2018.

Response:

It is difficult to forecast with certainty individual employees' retirement plans. In the years 2010 to 2012, approximately 17% of those FBC employees eligible to retire with an unreduced pension elected to do so. Using this assumption to forecast expected retirements from 2013 to 2018, and based on retirement eligibility data as of January 1, 2013, the number of FBC employees that are expected to retire with unreduced pensions between 2013 and 2018 are set out in the following table.

Number of FBC Employees Expected to Retire with an Unreduced Pension Between 2013 and 2018

2013	2014	2015	2016	2017	2018
10	12	16	19	22	25

139.2 Please provide the number of FBC employees that are expected to retire with reduced pensions between 2013 and 2018.

Response:

It is difficult to forecast with certainty individual employees' retirement plans. In the years 2010 to 2012, approximately 3% of those FBC employees eligible to retire with a reduced pension elected to do so. Using this assumption to forecast expected retirements from 2013 to 2018, and based on retirement eligibility data as of January 1, 2013, the number of FBC employees that are expected to retire with reduced pensions between 2013 and 2018 are set out in the following table.

Number of FBC Employees Expected to Retire with a Reduced Pension Between 2013 and 2018

2013	2014	2015	2016	2017	2018
3	3	3	3	3	3

139.3 For FBC only, what percentage of those eligible to retire with a reduced or unreduced pensions have exercised their retirement option between 2008 and 2012?

Response:

The percentage of FBC employees who were eligible to retire with a reduced or unreduced pension who exercised their retirement options between 2008 and 2012 is shown in the following table.

% of FBC Employees Eligible to Retire Who Retired 2008-2012

	2008	2009	2010	2011	2012
% of Employees Eligible to Retire With a Reduced or Unreduced Pension Who Retired	16%	9%	16%	15%	13%

140.0 Reference: Exhibit A2-1; Exhibit B-1, p. 164

Human Resources - Five Year Workforce Plan

"The need to focus on workforce planning, attraction and retention, and training and development services will continue throughout the 2014-2018 test period. In response to an aging workforce, HR will continue to focus on forecasting retirement rates, targeting recruitment efforts, developing internal leadership capability, and building specific technical knowledge." (Exhibit B-1, p. 164)

140.1 Please provide a breakdown of the Human Resources department costs associated with implementing the five year workforce plan, including workforce planning, targeted recruitment and developing internal talent, with a description of the activities associated with those costs. Please provide the breakdown for each of approved 2012, actual 2012, approved 2013 and projected actual 2013.

Response:

The Company did not separately track the costs associated with implementing the workforce plan in 2012 and 2013, as the related activities were considered to be part of the core HR functions and accomplished within existing regulatory approved O&M budgets.

The Human Resource activities associated with implementing the workforce plan to date include:

- Identifying and monitoring retirement eligibility and activity;
- Posting positions, as required;
- Reviewing internal talent pools and conducting external recruiting to fill posted positions (including advertising positions, short-listing and interviewing candidates, making recommendations for hire, and completing the job offer process); and
- Onboarding successful candidates in terms of benefits, pensions and other human resource programs and processes.

These activities are necessary to ensure that FBC is able to attract qualified, competent, talent to meet its demographic challenges and continuing industry demand.

141.0 Reference: Exhibit A2-1, Appendix C; Exhibit B-1, p. 113

O&M - Five Year Workforce Plan

141.1 Please provide a breakdown of the 2012 approved, 2012 actual, 2013 approved and 2013 projected actual O&M related to implementing the 2013 – 2017 Workforce Plan, including the following details:

- Business Area / Department;
- Positions and number of positions;
- Costs and the activities associated with the costs.

Response:

The Company did not separately track the costs associated with implementing the workforce plan in 2012 and 2013, as the related activities were considered to be part of the core business functions and accomplished within existing regulatory approved O&M budgets.

142.0 Reference: Exhibit B-1, p. 126

Operations - Resourcing

"The electric operations group continues to face the challenge of an aging workforce in the utility trades, as was described at length in the Company's 2012-2013 RRA. The operations group continues to actively try to recruit skilled workers into these positions and in 2012, 6 new apprentice PLTs were recruited to help assist in the long term resource plan."

142.1 For each of approved 2012, actual 2012, approved 2013 and projected 2013, please provide the number of new PLT apprentices, CPC technician apprentices and system power dispatchers with a breakdown of the costs associated with training and salaries for these new apprentices.

Response:

Please refer to the following table for the costs associated with training and salaries for the new PLT apprentices, CPC Technician Apprentices, and System Power Dispatchers for 2012 and 2013.

Training and Salary Costs for PLT Apprentices, CPC Technician Apprentices and System Power Dispatchers for 2012 and 2013

	Number Hired				Training Costs*			
	2012 Approved	2012 Actual	2013 Approved	2013 Projected	2012 Approved	2012 Actual	2013 Approved	2013 Projected
PLT Apprentices	2	4	6	6	$184,053	$120,389	$427,272	$155,495
CPC Apprentices	2	0	2	0	$99,762	$6,648	$19,949	$1,157
System Power Dispatchers	3	2	3	1	$849,133	$695,427	$652,049	$227,887

** Training costs include salaries and incremental costs (i.e. tools)*

The difference between approved and actual training costs can be attributed in part to the fact that FBC did not proceed with PLT apprentice schooling in 2012 and 2013. This was the result of the pending resolution of a related grievance.

142.1.1 Please provide the number of new PLT apprentices, CPC technician apprentices and system power dispatchers that FBC plans to recruit in 2014 with a breakdown of the costs associated with training and salaries for these new apprentices.

Response:

Because of the training period associated with apprentices becoming fully qualified tradespeople, FBC anticipated its hiring needs in 2012 and 2013, and did not plan for any recruitment of these positions in 2014.

143.0 Reference: Exhibit B-1, p. 164-167

Governance

"The governance department consists of legal services, insurance and risk management, and internal audit." (Exhibit b-1, p. 164)

143.1 Please provide a breakdown of the labour and non-labour expenses in this department, identifying which services they pertain to (legal, insurance and risk management, internal audit).

Response:

The table below provides the breakdown of labour and non-labour expenses for Legal, Insurance and Risk Management, and Internal Audit.

Legal	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ -	$ -	$ 95	$ 95	$ 102
Non-Labour	385	324	250	414	414	416
Total O&M	$ 385	$ 324	$ 250	$ 509	$ 509	$ 518

Insurance and Risk Management	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ -	$ -	$ 64	$ -	$ -	$ -
Non-Labour	1,539	1,399	1,435	1,471	1,588	1,596
Total O&M	$ 1,539	$ 1,399	$ 1,499	$ 1,471	$ 1,588	$ 1,596

Internal Audit	2010 Actual	2011 Actual	2012 Actual	2013 Approved	2013 Projection	2013 Base
Labour	$ 284	$ 215	$ 248	$ 333	$ 333	$ 357
Non-Labour	76	93	136	60	60	60
Total O&M	$ 360	$ 308	$ 384	$ 393	$ 393	$ 417

143.2 Please explain the 13 percent increase in non-labour expenses for 2013 Projection versus 2012 Actual. Provide a breakdown for each of the services and clearly identify the amounts charged from FHI or from FEI. For Insurance charges, please provide a further break down into labour charges from FHI, insurance premiums, and insurance claims.

Response:

Non-labour Expenses (000's)	2012 Actual	2013 Projection	Variance
Internal Audit	$136	$60	$(76)
Insurance & Risk Management	$1,435	$1,588	$153
Legal Services	$250	$414	$164
Total	$1,821	$2,062	$241 (13%)

Internal audit expenses have decreased by $76 thousand due to reduced intercompany cross charges from FHI. Less work is expected to be completed by FHI internal audit staff for FBC audit engagements. Approximately $2,200 of non-labour expenses (mainly travel expense) was charged from FHI to FBC during 2012.

Insurance and risk management expenses have increased by $153 thousand due to an increase in insurance premiums year-over-year, payment of a one-time large insurance deductible in 2012, an increase in first and third party claims in 2012, less a one-time refund of self-insurance reserve as approved in the 2012-2013 RRA decision to customers of $447 thousand. From 2012 actual to 2013 projection, approximately $150 thousand is directly attributable to the projected increase in insurance premiums which are impacted by market factors outside the control of FBC. There are no cross charges from FHI to FBC Governance related to insurance and risk management expenses. For 2013, projected expenses are insurance premiums of $1,422 thousand, appraisal fees of $60 thousand, and first and third party liability expenses of $106 thousand. The 2012-2013 Revenue Requirements application identified Asset Valuation (i.e. appraisal fees) of $60 thousand for the 2012 calendar year which was actually incurred in February 2013 due to availability of asset valuation services with an independent third party.

Legal services expenses have increased by $164 thousand due to those circumstances described in Section C4.16.3. Non-labour includes legal services provided by FHI as well as use of third party legal firms. This ratio is dependent upon factors driving the actual nature of the legal services required throughout the year. Approximately $5 thousand of non-labour expenses (mainly travel expense) was charged from FHI to FBC during 2012.

"FBC is proposing that variances from forecasts of third-party premiums be subject to deferral and refunded to, or recovered from, customers in later years. This deferral treatment is even more appropriate in a long-term PBR as proposed in this application." (Exhibit B-1, p. 166)

143.3 Please provide the approved versus actual third-party insurance premiums for FBC over the last five years. Include column showing the variance.

Response:

Insurance Premiums:

	Forecast	Actual	Variance
2008	1,331,160	1,294,369	36,791
2009	1,398,004	1,210,868	187,136
2010	1,370,450	1,159,002	211,448
2011	1,211,000	1,216,582	<5,582>
2012	1,272,000	1,275,616	<3,616>

"Internal audit is a stable department which is comprised of three employees. The forecast for internal audit reflects the expected net charges to the Gas division." (Exhibit B-1, p. 165)

143.4 Please explain whether the three employees in internal audit are included in the labour expenses or the non labour expenses as cross charges to FEI, or both?

Response:

Salaries for the three employees are included in the labour expenses section. Cross charges are credited in the labour expenses section so the numbers shown are net of cross charges to the Gas division.

143.5 If any cross charges are from FEI, please explain why this is necessary when there are three internal employees in this department. What functions do they service?

Response:

The Director, Internal Audit manages the audit departments of both the Electric and Gas utilities. Efficiencies are gained by using appropriate resources for different audits – optimally one auditor can perform the same audit (i.e. Accounts Payable) in both utilities simultaneously or back-to-back. This helps to ensure that processes, policies and internal controls are standardized including efficiencies gained through streamlined reporting. In addition, this approach provides excellent cross-training opportunities.

Qualifications, experience, timing and staff availability all are factors determining the resource best suited to complete the audit. For example, auditors from one utility need to assist the other utility in covering maternity leaves or vacation periods, which reduces the requirement for external contracted assistance. An example of another benefit is that the audit department of the Gas utility has hired an IT auditor. This single IT auditor provides the expertise to carry out IT specific audits for both the Electric and Gas utilities. This thereby reduces the requirement for use of external contracted assistance of this same skillset and/or hiring of an additional resource for IT audit needs within the Electric utility.

143.6 Table C4-2 indicates that there is an over expenditure of $117 thousand over the 2013 Approved budget for this department. Please clearly explain what this relates to.

Response:

Table C4-2 identifies Governance as having a projected over expenditure of $117 thousand over the 2013 approved budget. Governance is comprised of Internal Audit, Legal Services, as well as Insurance and Risk Management. The $117 thousand over expenditure is related to Insurance and Risk Management. The 2012-2013 Revenue Requirements application identified Asset Valuation (i.e. Appraisal Fees) of $60 thousand for the 2012 calendar year which was actually incurred in February 2013 due to availability of asset valuation services with an independent third party. In addition, there is a projected premium increase of $65 thousand over the 2013 approved budget due to those factors as outlined within BCUC IR 1.143.2. Lastly, there was an $8 thousand positive variance for FHI Insurance Services provided to FortisBC resultant from cross charges to Finance and not Governance.

144.0 Reference: Exhibit B-1, p. 167-174; Appendix F2

Corporate

FBC describes that the Corporate services provided by Fortis Inc. are "strategic, corporate governance in nature, provide access to the equity capital markets and furnish equity funding of the utility…" (Exhibit B-1, p. 168). FBC also indicates that this department includes internal audit activities.

144.1 Please explain why 'internal audit' expenditures are included in the Governance department and also in the Corporate department.

Response:

The internal audit functions mentioned in this section (C4:4.17.2.1) are at the Fortis Inc. level and are included as part of the overall corporate services which are charged out to all subsidiaries. Oversight of all subsidiary internal audit activity is undertaken by Fortis Inc. internal audit. Actual audit activities are carried out at the subsidiary level for both the Electric and Gas utilities by the Internal Audit department included in the Governance department only.

The Electric and Gas utilities benefit from Fortis Inc.'s internal audit group through sharing of audit programmes, comparison of risk profiles from across all subsidiaries, and information sharing of industry specific operational environments within all subsidiary jurisdictions thereby enhancing understanding of potential changes to the local environment.

144.2 Please explain the $1 million reduction in Corporate O&M expenses in 2012 versus 2011 Actual.

Response:

The table below provides the decrease in Corporate O&M in 2012 from 2011.

Corporate	2011	2012	Variance	Explanation
Fortis Inc Charges	1,612	1,868	256	Increased Fortis Inc charges
Board of Director	268	241	(27)	Lower Board costs
Executive	2,294	1,622	(672)	Lower labour and non-labour Executive costs
Other	310	(287)	(597)	Primarily due to fringe benefit load variance and increased non-regulated activity recoveries partially offset by higher corporate expenses. Please also refer to BCUC IR 1.144.8
Total	**4,484**	**3,444**	**(1,040)**	

144.3 Table C4-2 indicates that there is a $425 thousand ‘sustainable savings’ in this department which is carried forward into the 2013 Projection. Please explain which of the department functions this relates to. Provide the breakdown in a table format if appropriate.

Response:

Please refer to the response to BCUC IR 1.96.2.

FBC explains the Executives costs as: “The labour expense consists of Executive salary and benefits directly paid by FBC and cross charges from FEI for Executive oversight from those Executive employed by FEI, offset by cross charges to FEI for Executive oversight from those Executive employed by FBC.” (Exhibit B-1, p. 171)

144.4 Please explain why cross charges to/from FEI are not included in the labour expenses rather than non-labour expenses?

Response:

Cross charges to/from FEI are included in labour expenses for Corporate Executive and in non-labour expenses for all other departments.

> "In the summer of 2010, FBC and the FEI began sharing common members of the Executive. The integration of the Executive has evolved such that all Executive have joint oversight of FBC and FEI effective January 1, 2012." (Exhibit B-1, p. 172)

144.5 Please clarify whether all of the executives for FBC and FEI are now all integrated with joint oversight. Or are there still some FBC-specific executives and FEI-specific executives? In other words, are they included in each separate Company's payroll?

Response:

Effective January 1, 2012, all executives for FBC and FEI have joint responsibilities in both companies. Although all executives for FBC and FEI have joint responsibilities in both companies, the executives are included in each separate company's payroll with cross charges from those executive employed by FEI, offset by cross charges to FEI for executive employed by FBC (refer to Tab C Section 4 page 171 rows 29-31).

> "The results of the Massachusetts Formula for 2013 would allocate approximately 23 percent of the Executive pooled costs to FBC. FBC is requesting approval to allocate the pooled Executive costs (fully loaded labour costs with no overhead) to FBC and FEI using the Massachusetts Formula effective January 1, 2014." (Exhibit B-1, p. 172)

144.6 Please clarify whether FEI is also seeking approval for this pooled allocation method in its current PBR Application and that the costing in the PBR Application is based on this allocation methodology?

Response:

To clarify, both FEI and FBC are seeking approval to change the estimation of time allocation from an Executive time estimate to an estimate derived from the Massachusetts Formula. This methodology will be applied to each Executive's benefit loaded salary (excluding overhead charges). The only change, therefore, is in the allocation of time, as the individual executive cost is based on each executive's fully loaded salary, consistent with the method approved in the 2012/13 RRA Decision. The allocator is applied to each Executive's benefit loaded salary.

Any change in the Executive costs as a result of changes in percentage allocation driven by the Massachusetts formula versus an Executive estimate will be absorbed as part of the O&M formula under PBR for both FEI and FBC.

144.7 Can it be assumed that by applying the Massachusetts Formula for 2013, FEI would be allocated the remaining 77 percent of the pooled Executive costs, or would some other portion be allocated to another entity or to a non-regulated business unit?

Response:

By applying the Massachusetts formula for 2013, FBC would allocate approximately 77 percent of the fully loaded Executive costs to FEI. The one exception to this would be one VP, who would be charged to FHI at approximately 77 percent of his fully loaded wage.

To clarify the concept of fully loaded costs, this would include regular base pay (net of time away) plus a general benefits loading. Since FBC and FEI do not forecast individual benefits attributable for each Executive or employee, such as post-employment benefits, incentives, etc., a general benefit loading rate is applied to regular base pay (net of time away) to incorporate all such benefits for each employee. Included in the general benefit loadings are pension and OPEB expenses, short-term incentives and other benefits. Those Executive compensation costs that are funded by the shareholder, such as stock options and PSUs, are excluded from the general benefits loading and regulated O&M and therefore are not included in the fully loaded Executive costs subject to the Massachusetts Formula allocation methodology. Therefore under the Massachusetts formula, approximately 77 percent of the fully loaded salary of the Executive residing in FortisBC Inc. would be allocated to FEI (and FHI as described above) and approximately 23 percent of the Executive residing in FEI and FHI would be allocated to FortisBC Inc.

The allocation methodology used in 2012 and 2013 is based on Executive estimation of time allocation applied against the fully loaded Executive costs. As part of the 2014-2018 PBR RRA, FBC has maintained the use of the fully loaded benefit methodology and has proposed to apply the Massachusetts Formula allocation methodology for Executive compensation costs to replace the Executive's estimation of time, effective January 1, 2014.

In Table C4-37, FBC provides a summary of the Corporate Other expenditures. A truncated copy of the table is included below:

2010 Actual	2011 Actual	2012 Actual
(576)	310	(287)
$ (576)	**$ 310**	**$ (287)**

FBC explains that "The 2010 and 2012 amounts primarily include recoveries of executive time working on non regulated activities." (Exhibit B-1, p. 172)

144.8 If 2010 and 2012 are primarily due to recoveries in non-regulated activities then please explain the actual expenses in 2011,

Response:

The statement, "The 2010 and 2012 amounts primarily include recoveries of executive time working on non regulated activities" is not correct.

The statement should have read "The 2010 and 2012 recoveries include charges for non-regulated activities and an over allocation of the O&M portion of fringe benefit loading to departmental labour offset by corporate expenses".

The 2011 expense was due to recoveries from non-regulated activities being more than offset by a under allocation of the O&M portion of fringe benefit loading to departmental labour and corporate expenses.

The O&M portion of fringe benefit loadings are allocated to the various O&M departments based on a forecasted rate usually set at the beginning of the year, for administrative ease any over or under allocation of actual O&M portion of fringe benefits settle to Corporate Other O&M.

144.9 Please explain the fluctuation of the charges in this functional area.

Response:

Corporate Other amounts vary from year to year and can result in a net recovery or net expense. In fact 2008 and 2009 were also net expenditures of $0.1 million and $0.7 million, respectively. The expenditures / recoveries in this account in the past have included unbudgeted recoveries of Executive time working on non-regulated activity in 2010, unbudgeted variances in the fringe benefit load rate, and other corporate expenditures as they occurred, such as those dealing with labour issues and other one-time project costs.

Please refer to the response to BCUC IR 1.144.8.

145.0 Reference: Exhibit B-1, p. 176

O&M - Advanced Metering Infrastructure Impact

The total O&M impact of the AMI Project in 2014 Forecast is $368 thousand in Table C4-44.

145.1 Please confirm that $368 thousand represents the net incremental cost of the AMI project in 2014.

Response:

Confirmed. The $368 thousand shown in Table C4-44 from Exhibit B-1 represents the net incremental O&M cost of the AMI project in 2014.

145.2 Please discuss why there are no AMI project cost adjustments to the O&M formula on Table B-6-5.

Response:

Table B6-5 does include an adjustment related to the O&M impacts from AMI. The adjustment is reflected on line 23 of Table B6-5.

As detailed in section B6.2.4.2 of the application, AMI-related expenses and reductions have been excluded from the formula (tracked outside the formula) as the expenditure/savings profile is highly variable during the implementation period of the project (2013 – 2015).

145.3 Does FBC anticipate that there will be AMI project cost adjustments to the O&M formula in future years? Please discuss why or why not.

Response:

No. As noted in the response to BCUC IR 1.145.2 above, FBC has proposed to track the O&M impacts resulting from AMI outside the PBR O&M formula. As noted in the response to BCPSO IR 1.39.1, if the forecast O&M reductions from AMI change over the course of the PBR plan, then FortisBC would update its forecast.

G. PBR FORECAST – CAPITAL EXPENDITURES

146.0 Reference: Exhibit B-1, pp. 281

Table 1-A-1 – Additions to Plant in Service (2013)

Capital Expenditures

146.1 Please provide a list of all completed capital expenditures that FBC proposes to recover in rates in 2013. The listing must include:

- The original forecast in-service date;
- The actual in-service date;
- The Commission-approved budget;
- The actual amount spent at completion;
- The variance amount and percent;
- Comments on the variance in costs and schedule.

Response:

FBC believes this question must be referring to all 2012 capital expenditures proposed to be recovered in 2013 rates. All capital expenditures recovered in rates in 2013 would include all expenditures not fully depreciated, which (based on depreciation periods) would include up to 50 or more years' expenditures.

Please note that in 2013, rates are set based on Approved Capital Expenditures / Approved Rate Base and are not based on "Actual Capital Expenditure / Actual Plants in Service". However, a table is provided below with 2012 Gross Loaded Actual & Budgeted Expenditure data per the request above. Gross Loaded data is provided per the information request, since it is the Loaded Capital Expenditure that is recovered in rates. The carryover of capital expenditures from 2012 to 2013 as detailed below is primarily a result of the timing of the 2012-2013 RRA Decision.

Line	REGULATED CAPITAL PROJECTS	Planned Plant In Service Date	Actual Plant In Service Date	2012 Actual Expenditure	2012 BCUC Approved Budget	Difference over/(under)	Difference over/(under)	VARIANCE/SCHEDULE COMMENTS
1	**Hydraulic Production:**				($000s)		%	
2	South Slocan Plant Automation	2011	2012	68	-	68	100%	Carry-over from 2011
3	All Plants Concrete & Structural Rehabilitation	2012	2012/2013	269	340	(71)	-21%	Cost Savings
4	Corra Linn Unit 3 Completion	2012	2012	281	274	7	2%	Minor budgetary variance
5	Upper Bonnington Spillgate Rebuild / Upgrade	2012	2012	1,614	1,065	548	51%	Carry-over from 2011
6	Lower Bonnington Power House Windows	2012	2012	463	366	97	27%	Carry-over from 2011
7	All Plants Minor Sustaining Projects	2012	2012/13	773	946	(173)	-18%	Carry-over to 2013
8	Upper Bonnington Old Plant Various Unit Upgrades	2012/2013	2012/2013	217	507	(290)	-57%	Carry-over to 2013
9	Lower Bonnington, Upper Bonnington & Corra Linn Fire Panels	2012	2012	280	250	30	12%	Minor budgetary variance
10	All Plants Upgrade Station Service Supply	2012	2012	1,217	674	543	80%	Carry-over from 2011
11	Corra Linn Unit 1 Life Extension (replace Turbine)	2011	2012	46	-	46	100%	Carry-over from 2011
12	Corra Linn Unit 2 Life Extension (replace Turbine)	2012	2012/2013	2,600	3,438	(838)	-24%	Cost Savings
13	South Slocan Fire Panel	2011	2012	24	-	24	100%	Carry-over from 2011
14	Lower Bonnington & Upper Bonnington Plant Totalizer Upgrade	2012	2012	32	90	(58)	-65%	Cost Savings
15	Queen's Bay Level Gauge Building Ph.1	2009	CWIP	3	-	3	100%	Carryover work from 2009 due to land access difficulties
16	**Subtotal Hydraulic Production**			**7,886**	**7,950**	**(64)**	**-1%**	
17	**Transmission Plant:**							
18	Ellison Sexsmith Transmission Tie	2012	2013	125	6,538	(6,413)	-98%	Carry-over to 2013
19	Okanagan Transmission Reinforcement	2012	2012	3,825	2,219	1,606	72%	Carry-over from 2011
20	Huth Split Bus	2011	2012	1,266	-	1,266	100%	Carry-over from 2011
21	Capitalized Inventory	CWIP	CWIP	247	-	247	100%	Changes in inventory levels
22	Backbone Transport Technology Migration	2012	CWIP	28	14	14	105%	Minor budgetary variance
23	Transmission Line Sustaining	2012	2012/13	6,070	8,517	(2,446)	-29%	Carry-over to 2013
24	Station Sustaining	2012	2012/13	7,364	14,123	(6,759)	-48%	Carry-over to 2013, PCB scope reduction and shift in schedule
25	**Subtotal Transmission Plant**			**18,925**	**31,411**	**(12,486)**	**-40%**	
26	**Distribution Plant:**							
27	New Connects System Wide	2012	2012	15,665	22,276	(6,611)	-30%	Lower than anticipated 2012 Customer activity
28	Distribution Unplanned Growth Projects	2012	2012	777	839	(62)	-7%	Minor budgetary variance
29	Distribution Small Growth Projects	2012	2012/13	639	1,075	(436)	-41%	Carry-over to 2013
30	Distribution Sustainment	2012	2012/13	8,913	10,922	(2,009)	-18%	Carry-over to 2013
31	**Subtotal Distribution Plant**			**25,994**	**35,112**	**(9,118)**	**-26%**	
32	**General Plant:**							
33	Distribution Substation Automation	2011	2012	37	-	37	100%	Minor budgetary variance
34	Protection Upgrades (F.A. Lee Stn. to Vernon 230kV Protection Upgrade)	2011	2012	(403)	-	(403)	100%	Carry-over credit from 2011
35	Communication Upgrades	2012	2012	388	403	(14)	-4%	Minor budgetary variance
36	Mandatory Reliability Compliance (MRC)	2011	2012	112	-	112	100%	Carry-over from 2011
37	Buildings	2012	2012	1,536	1,368	168	12%	Minor budgetary variance
38	Kootenay Long Term Facility Strategy (Kootenay Ops Centre)	2011	2012	360	-	360	100%	Moved to Deferred in 2013-CPCN
39	Okanagan Long Term Solution	2012	2012	48	69	(21)	-30%	Carry-over to 2013
40	Central Warehousing	2012	2013	1,634	1,764	(130)	-7%	Minor budgetary variance
41	Furniture & Fixtures	2012	2012	113	122	(8)	-7%	Minor budgetary variance
42	Fleet	2012	2012	1,959	2,432	(474)	-19%	Carry-over to 2013
43	Telecommunications	2012	2012	99	122	(23)	-19%	Minor budgetary variance
44	Infrastructure Sustainment	2012	2012	1,219	1,116	103	9%	Minor budgetary variance
45	Desktop Infrastructure Sustainment	2012	2012	1,223	1,120	103	9%	Minor budgetary variance
46	Applications Enhancements	2012	2012	1,267	1,240	27	2%	Minor budgetary variance
47	Application Sustainment	2012	2012	1,192	1,184	8	1%	Minor budgetary variance
48	Power Sense DSM Reporting Software	2012	2013	115	1,020	(905)	-89%	Shift in schedule to 2013
49	Meter	2012	2012	446	405	41	10%	Minor budgetary variance
50	Tools	2012	2012	531	530	1	0%	Minor budgetary variance
51	**Subtotal General Plant**			**11,876**	**12,895**	**(1,019)**	**-8%**	
52	**Total Gross Loaded Expenditure**			**64,680**	**87,368**	**(22,688)**	**-26%**	
53								
54	**Cost of Removal (COR)**			**3,710**	**4,260**	**(550)**	**-13%**	Carry-over to 2013

147.0 Reference: Exhibit B-1, pp. 58, 179, and 180; Appendix E pp. 278-284

Capital Expenditures

147.1 Please clarify whether the Total Gross Capital Expenditures for all columns in Table C5-1 include or do not include adjustments for reconciliation to the Capital Plan.

Response:

The Total Gross Capital Expenditures in Table C5-1 include adjustments for reconciliation to the respective capital plans for the years shown in the table, which is consistent with the adjustments for 2013 expenditures as shown in Table 1-A-1. These adjustments include removal of capitalized overheads, direct overheads, and AFUDC, as well as the inclusion of costs of removal for the total gross capital expenditures shown.

147.1.1 Please reconcile Table C5-1 against Table 1-A-1 for the year 2013 Approved and 2013 Projected.

Response:

The reconciliation of 2013 Projected Capital Expenditure of $133,193k has already been reconciled at Table 1-A-1 (Exhibit B-1, Tab E, Page 282, Lines 67 to 72).

The table below provides the reconciliation of the 2013 approved of $119.519 million to $101.970 million in Table C5-1.

	CWIP Dec. 31, 2012	Approved Expenditures 2013	CWIP Dec 31, 2013	Additions to Plant in Service
	($000s)			
TOTAL	16,448	119,519	10,482	125,485

Reconciliation to Capital Plan	
Less Capitalized Overheads	(11,255)
Less Direct Overheads	(4,650)
Less AFUDC	(2,515)
Add Cost of Removal	3,344
CIAC Adjustment	(2,473)
Total Capital in Table C5-1 2013 Approved	101,970

147.2 Please add the 2013 Projected total capital expenditure to Table B6-7, and remove the AMI capital expenditures.

Response:

FBC believes that this is a request to recalculate the capital expenditures over the PBR period using 2013 Projected capital instead of 2013 Base capital. Please see the following table:

Line No.	Particulars	2013 Base	2013 Projected	2014 Formula	2015 Formula	2016 Formula	2017 Formula	2018 Formula
		(1)		(2)	(3)	(4)	(5)	(6)
1	**2013 Base Capital ($000)**	$ 49,180	$ 59,927					
2	Less Capital Tracked Outside of Formula							
3	Pension/OPEB (Capital portion)	(6,741)	(6,741)					
4		42,439	53,186					
5								
6	Average Number of Customers	128,796	128,796	129,770	130,922	132,142	133,385	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)**			54,558	56,099	57,662	59,288	60,943
16	Add: Capital Tracked Outside of Formula							
17	Pension/OPEB (Capital portion)	6,741	6,741	6,396	5,952	5,508	5,133	4,826
18	PCB Compliance - Substations			6,062				
19	Advanced Metering Infrastructure Project			-	-	-	-	-
20								
21	**Total Capital Under PBR**			**67,016**	**62,051**	**63,170**	**64,421**	**65,769**

Note: The total capital under the PBR is calculated with the 2013 Projected Base of $53.186 million.

147.2.1 From the new total capital expenditures table, provide the average capital expenditures for the years 2014 to 2018.

Response:

Using the 2013 Projected to determine the formulaic capital for the PBR period (as detailed in response to BCUC IR 1.147.2 above) results in average annual capital expenditures of $64.486 million for 2014 – 2018.

147.2.2 Explain and justify why the base year should be set at a Total Gross Capital Expenditure of $133,193,000 (adjusted amount) rather than the average amount of approximately $60,211,000 forecast between 2014 and 2018.

Response:

For clarity, FBC did not set the base year using the Total Gross Capital Expenditure of $133,193 thousand as this figure is only a projection for 2013, and includes major non-recurring projects such as the acquisition of the City of Kelowna's distribution assets. The average amount of approximately $60,211 thousand referenced in the question is derived from the proposed PBR formula using a 2013 Base of $49.18 million, and does not represent a forecast of expenditures for the 2014 – 2018 period. Please also see Figure B6-3 from the Application which provides a comparison of the formulaic capital to the forecast capital for the 2014 – 2018 PBR period.

Recognizing that the base year capital expenditures to be used as an input for the 2014-2018 formula should be based on capital expenditures that have already undergone a full public review, FBC has used the 2013 approved capital expenditures of $101.97 million from the 2012-2013 RRA as the starting point for the capital formula. When the 2013 approval capital expenditures are adjusted for non-recurring projects and non-controllable items as detailed in Table C5-2, a 2013 Base of $49.18 million results.

FBC has not included an adjustment in the 2013 Base calculation for capital projects related to the former City of Kelowna utility assets acquired in 2013, as the Company intends to absorb these future capital expenditures related to those assets within the capital funding as calculated under the proposed formula.

147.3 Please explain the sizeable downturn in Total Gross Capital Expenditure from 2013 to 2014.

Response:

Total Gross Capital Expenditures include major capital projects. In order to properly compare annual levels of capital expenditures, it is necessary to remove the expenditures related to major capital projects as these expenditures can vary significantly from year-to-year depending on the scope and number of major capital projects underway. Once these adjustments are accounted for (as further detailed below), it is apparent there is no downturn in capital expenditures from 2013 to 2014.

The approved 2013 Total Gross Capital expenditures of $101.970 million include expenditures related to the following major projects:

- PCB Environmental Compliance (Stations);

- Kelowna Bulk Transformer Capacity Addition;
- Trail Office Lease Purchase;
- Kootenay Long Term Facility;
- Okanagan Long Term Solution; and
- Advanced Metering Infrastructure.

Excluding the 2013 expenditures related to these projects results in a 2013 Base of $49.180 million (including PST and Pension adjustments as detailed in Table C5-2).

The following major projects have expenditures in 2014:

- PCB Environmental Compliance (Stations);
- Okanagan Long Term Solution; and
- Advanced Metering Infrastructure.

When the 2014 forecast Total Gross Capital Expenditures of $75.176 million (as provided in Table C5-3) are adjusted to exclude any expenditures related to the projects listed above, the 2014 forecast for capital expenditures becomes $52.229 million in 2014. Thus, the appropriate comparison of annual capital expenditures becomes $49.180 million in 2013 to $52.229 million in 2014, or an increase of $3.049 million, of which approximately $1.75 million is related to pension and PST adjustments.

148.0 Reference: Exhibit B-1, pp. 178-179

Historical Capital Expenditures

G-110-12 & the Decision

FBC states the "…spending for 2013 is projected to be approximately $6 million less than approved." (p. 176)

On page103 of the 2012-2013 RRA and ISP Decision, the Commission identified a number of areas where further reductions are possible. The total of the reductions was $17.6 million. The Decision determined that only a 60% reduction would be applied to "…provide FortisBC with sufficient flexibility to prioritize expenditures in a cost-effective fashion."

148.1 Considering the above, please provide further discussion that justifies employing a base of $101.97 million for the PBR.

<u>**Response:**</u>

For clarity, FBC has proposed a base level of capital expenditures of $49.180 million as detailed in Table C5-2 of the Application. This is based on 2013 approved expenditures of $101.970 million, adjusted for certain items including Major Projects, as per Table C5-2. FBC considers the proposed base level of capital expenditures necessary in order to provide ongoing safe and reliable service to the customers. While it may be possible to reduce expenditures in the short term (at increased system risk) as was directed by Commission in Order G-110-12, FBC does not consider this to be prudent long-term approach as investment levels will not be sufficient in order to maintain adequate levels of safety and reliability.

148.2 In order to provide additional justification, please complete and, if necessary, correct the data in the following table:
Capital Expenditures in Nominal Dollars ($millions)

	Capital Expenditures in Nominal Dollars ($millions)								
Capital Expenditures	2007	2008	2009	2010	2011	2012	2013 Approved	2013 Projected	2014 Projected
Forecasted/Projected								133.193	72.758
Approved						83.052	101.970		

Actual				130.481	76.209	52.393			

Capital Expenditures in Nominal Dollars ($millions)									
Capital Expenditures	2007	2008	2009	2010	2011	2012	2013 Approved	2013 Projected	2014 Projected
Forecasted/Projected								133.193	72.758
Approved						83.052			
Actual				130.481	76.209	52.393			

Response:

Please refer to the table provided below. For 2007 – 2012, "forecast" and "approved" values are the same. FBC will update the 2013 Projection as part of the evidentiary update.

Please also refer to the response to the response to ICG IR 1.36.1.

	Capital Expenditures in Nominal Dollars ($millions)								
Capital Expenditures	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013 Approved**	**2013 Projected**	**2014 Projected**
Forecasted/Projected								133.193	72.758
Approved	119,834	112,888	116,419	153,095	78,677	83.052	101,970		
Actual	129,189	99,587	99,169	130.491	76.209	52.393			

148.3 In order to provide additional justification, please complete the following table using the Handy Whitman Index to make the adjustment to 2013$:

	Capital Expenditures in Real Dollars Adjusted to the Base Year - 2013 ($millions)						
Capital Expenditures	2007	2008	2009	2010	2011	2012	2013 Projected
Forecasted							

Approved							
Actual							
Handy-Whitman Index number							

Response:

The requested information is provided in the table below.

Capital Parameters	2007	2008	2009	2010	2011	2012	2013
Capital Expenditure - Nominal	($000s)						
Projected	-	-	-	-	-	-	133,193
Budget	119,834	112,888	116,419	153,095	78,677	83,052	101,974
Actual	129,189	99,587	99,169	130,491	76,209	52,392	
CPI % Actual	1.80%	2.10%	0.00%	1.30%	2.40%	1.10%	
Capital Expenditure - Real (2013$)	($000s)						
Projected	-	-	-	-	-	-	133,193
Budget	130,622	120,874	122,092	160,554	81,452	83,966	101,974
Actual	140,819	106,633	104,000	136,849	78,897	52,968	-
Handy-Whitman Index number	1.215	1.117	1.141	1.081	1.042	1.027	

149.0 Reference: Exhibit B-1, p. 182

Base Capital Expenditures

Table C5-2

149.1 Please explain why the amount for AMI of $24,985,000 was included as Other Capital when it was filed as a CPCN.

Response:

The AMI project is included as Other Capital in order to distinguish that project from the remaining CPCN projects identified in Section C5.4.7. The AMI Project, unlike the remaining CPCN projects in Section C5.4.7, is reflected in revenue requirements in this Application.

149.1.1 Please provide a detailed breakdown of the AMI costs that make up the amount of $24,985,000.

Response:

The costs of $24.985 million were provided as part of the 2012-2013 RRA and 2012 Long Term Capital Plan filed June 29, 2011. These forecasts costs were based on a preliminary high-level estimate of capital costs for the AMI project, and were subsequently updated in the CPCN application filed on July 26, 2012. The forecast costs associated with the AMI project will be updated as part of FBC’s evidentiary update to the 2014-2018 RRA.

149.2 Please explain why the amount for AMI of $24,985,000 is not the sum of the capital expenditure amount of $13,559,000 and the sustaining capital expenditure amount of -$146,000 as found in the AMI Proceeding, Exhibit B-50.

Response:

The adjustment of $24.985 is appropriate as it is this forecast (as provided in the 2012-2013 RRA) that comprises the 2013 Approved amount of $101.97 million as detailed in Table C5-2. The forecast costs associated with the AMI Project were updated as part of the CPCN application filed subsequent to the 2012-2013 RRA, however due to the timing of the AMI CPCN application these updated costs were not reflected in the forecast 2013 capital expenditures as presented in the 2012-2013 RRA. Please also refer to the responses to BCUC IRs 1.149.1.1 and 1.151.2.

150.0 Reference: Exhibit B-1, p. 181-182

Table C5-1 & Table C5-2

Major Projects

150.1 Please explain why the amount for Other - Major Projects of $34,985 in Table C5-1 does not agree with the amount in Table C5-2 of $42,996,000.

Response:

The total amount for Other – Major Project in Table C5-1 does not agree with the amount provided in Table C5-2 due to the fact that the Kootenay Long Term Facility ($7.980 million) and the Okanagan Long Term Solution ($0.031 million) were inadvertently included as Other – Regular Capital in Table C5-1. As the overall total for Other Capital remains unchanged, this error has no material impact to the Application. Please also refer to Errata No. 2.

150.1.1 Please provide justification for the amount of $16,146,000 for Other – Regular Capital as found in Table C5-1.

Response:

The amount of $16,146 thousand for Other – Regular Capital as shown in Table C5-1 is comprised of the following projects:

Other – Regular Capital	2013 Approved ($000s)
Buildings	$769
Furniture and Fixtures	$106
Fleet	$2,260
Telecommunications	$159
Meters	$353
Tools	$398
Information Systems	$4,089
Kootenay Long Term Facility	$7,980
Okanagan Long Term Solution	$31
Total	**16,146**

Note: Differences due to rounding

As noted in the response to BCUC IR 1.150.1 above, expenditures related to the Kootenay Long Term Facility as well as the Okanagan Long Term Solution were) were inadvertently included as Other – Regular Capital in Table C5-1. Please also refer to Errata No. 2.

Excluding these two projects results in a total of $8.134 million for Other Regular Capital, which corresponds with the amount shown for Other Capital applicable to the proposed PBR formula as detailed in Table C5-2 and in Table B6-6.

151.0 Reference: Exhibit B-1, p. 182

Base Capital Expenditures

Table C5-3

Other Capital - AMI

In Exhibit B-50 from the AMI proceeding, the summary of the amounts for capital and sustaining expenditures in Attachment BCUC IR3.6.1 are shown as follows:

Summary of Capital and Sustaining Expenditures taken from Exhibit B-50.						
AMI	2013	2014	2015	2016	2017	2018
Capital	$13,559,000	$18,501,000	$18,837,000	$ -	$ -	$ -
Sustaining	$ 162,964	$ 622,658	$ 894,293	$ 910,300	$1,071,384	$ 941,965
Total	$13,721,964	$19,123,658	$19,731,293	$ 910,300	$1,071,384	$ 941,965

151.1 Please explain the differences in the amounts shown in Table C5-3 and the table above, as the amounts in O&M are the same as found in Exhibit B-50.

Response:

The capital expenditures shown in the table above from Exhibit B-50 of the AMI proceeding include overheads and AFUDC whereas capital expenditures in this Application (Table C5-3) do not include overheads or AFUDC. This represents approximately $2.033 million and $1.177 million in 2014 and 2015 respectively. As well, the expenditures for AMI for 2014 and 2015 as shown in Table C5-3 also include the sustaining capital expenditures related to the IT component of the AMI project ($0.297 and $0.573 million respectively).

151.2 As the AMI project is anticipated to generate benefits, please explain if the net sustaining capital expenditures from the AMI application shown below have been included since they would reduce the sustaining capital expenditures. If not, please explain why not.

Summary of Net Sustaining Expenditures taken from Exhibit B-50.						
AMI	2013	2014	2015	2016	2017	2018
Sustaining	-$ 146,487	-$ 846,404	-$ 310,348	-$972,526	-$ 214,042	-$1,924,379

Response:

The two items identified in the AMI application as producing net savings in sustaining capital expenditures were the avoidance of metering reading handheld replacements and the avoidance of costs related to addressing Measurement Canada S-S-06 requirements. Given that neither of these costs are reflected in the 2013 Base, the savings related to those items are already inherently reflected in the sustaining capital expenditures identified in the application. In the absence of the AMI project, FBC would have been required to either adjust the 2013 Base upwards to address the impact of Measurement Canada's new S-S-06 requirements, or track the required expenditures related to compliance with S-S-06 outside of the proposed PBR formula.

152.0 Reference: Exhibit B-1, p. 182

UCA, Section 44.2 – Capital Expenditure Schedule

152.1 Will FBC be submitting new capital expenditures schedules at each mid-term review or annually for the next period?

Response:

At the Annual Review, FBC will submit financial schedules, including the formula-driven capital expenditure calculation, to support its revenue requirements. Detail of the Company's capital expenditures will continue to be included in its Annual Reports to the BCUC.

152.1.1 If so, will these capital expenditures schedules provide:

- A brief scope and a reference to the Long Term Capital Plan approved in 2012,
- A start date and an in-service date,
- The total estimate cost, the actual cost at completion and the carry-over cost.

Response:

Please see the response to BCUC IR 1.152.1.

153.0 Reference: Exhibit B-1, p. 182

UCA, Section 44.2 – Capital Expenditure Schedule

FBC states "A discussion of the Sustainment Capital, Growth Capital, and Other Capital categories is provided below. As well, a discussion is provided of projects that are not included in the table above, but for which FBC expects to submit applications for a Certificate of Public Convenience and Necessity during the 2014 – 2018 periods."

153.1 Please provide an update to the ISP/LTCP expenditures that was included in Appendix J in the 2012-2013 RRA and ISP Application, for the forecasted years 2014-2018 and explain any changes as a result of the PBR Application. Provide the updated list in Excel format.

Response:

Please refer to Attachment 153.1 for the Excel spreadsheet. Please note that project expenditures for which FBC intends to file an application for a CPCN are highlighted blue in the electronic attachment.

Please also refer to the responses to BCUC IRs 1.155.1, 1.170.1, and 1.171.1 for explanations regarding the differences between the forecast expenditures for 2014-2018 period as initially provided in the 2012 Long Term Capital Plan and the forecast 2014-2018 expenditures provided as part of the 2014-2018 RRA.

154.0 Reference: Exhibit B-1, p. 184

Asset Management

FBC states "FortisBC is pursuing the development of a common Asset Management Strategy across both the Gas and Electric divisions with the objective of improving maintenance and capital investment decisions, planning, and execution."

154.1 Please explain how FBC allocates the development cost of a common Asset Management Strategy between the Gas and Electric customers.

Response:

The costs of external consultants have been allocated evenly (50/50 split) between the Gas and Electric divisions. The individual staff participants from each division have been charging their time to their division.

154.2 Provide the actual cost to date for the development of a common Asset Management Strategy and the forecasted costs over PBR term.

Response:

The costs to date have been approximately $108 thousand for the electric division.

As the strategy is still under development, there is currently no detailed forecast of costs over the PBR term; the PBR formula driven budgets are sufficient to complete the development of the Asset Management Strategy.

155.0 Reference: Exhibit B-1, p. 188

Table C5-4 Forecast FBC Sustainment Capital Expenditures

Sustainment Capital Overview

155.1 Explain the differences in forecasted sustaining capital expenditures between the PBR forecast and the 2012 LTCP expenditures in Appendix J (2012-2013 RRA and ISP Application) for the forecasted years 2014-2018 that amounts to a shortfall of $70 million. See table provided below.

	2013	2014	2015	2016	2017	2018	2014-2018
	Base	Forecast	Forecast	Forecast	Forecast	Forecast	Total
Sustainment Capital (PBR)							
Generation	2,468	3,155	2,940	2,944	3,010	2,847	14,896
Transmission, Station & Telecommunications	8,359	16,171	9,821	9,480	11,073	11,520	58,065
Distribution	9,220	11,827	12,092	14,164	14,248	14,503	66,834
Total Sustainment Capital	20,047	31,153	24,854	26,587	28,331	28,869	139,794
2012 LTCP (Appendix J - Sustaining Capital)							
Generation	2,947	11,696	4,433	5,019	13,269	20,567	54,984
Transmission, Station & Telecommunications	25,141	17,398	19,449	17,125	11,887	19,329	85,188
Distribution	12,129	13,051	13,216	13,706	14,746	14,683	69,402
Total Sustainment Capital	40,217	42,145	37,098	35,850	39,902	54,579	209,574
Sustainment Capital (PBR-LTCP)							
Generation	(479)	(8,541)	(1,493)	(2,075)	(10,259)	(17,720)	(40,088)
Transmission, Station & Telecommunications	(16,782)	(1,227)	(9,628)	(7,645)	(814)	(7,809)	(43,905)
Distribution	(2,909)	(1,224)	(1,124)	458	(498)	(180)	(5,477)
Total Sustainment Capital	(20,170)	(10,992)	(12,244)	(9,263)	(11,571)	(25,710)	(69,780)

(Adapted from data provided in Exhibit B-1 and App. J of 2012-2013 RRA and ISP Application)

Response:

The difference between the amounts shown in the 2012 LTCP and the amounts included as part of the 2014 – 2018 RRA can be reconciled as follows:

- The expenditures shown in the 2012 LTCP include overheads (capitalized and direct) and AFUDC, whereas the capital expenditures in Table C5-4 are unloaded and do not include AFUDC. With loadings and AFUDC excluded from the 2012 LTCP, the difference between the 2012 LTCP and Table C5-6 becomes approximately $36.5 million.

- Appendix J of the 2012 LTCP included expenditures related to the Corra Linn Spillway Concrete and Spill Gate Rehabilitation as well as the Upper Bonnington Old Unit Repowering. As these are considered Major Projects (CPCNs) for the purposes of the

2014-2018 PBR, they are not included in Table C5-4. Excluding the expenditures related to these Major Projects from the 2012 LTCP narrows the difference between the sustaining expenditures presented in the 2012 LTCP and those shown on Table C5-4 for the 2014 – 2018 period to approximately $4.3 million.

This difference of $4.3 million between the 2014 - 2018 expenditures presented in the 2012 LTCP as compared to Table C5-4 is primarily the result of shifts in the timing of a number of projects, updates to forecast expenditures for the PBR period, as well as the addition of certain Distribution Sustainment projects (not identified in the 2012 LTCP) related to the acquisition of the City of Kelowna distribution assets.

155.2 Provide an explanation as to how this reduction will not negatively affect the "2012 LTCP approved" operation of the utility.

Response:

As explained in the response to BCUC IR 1.155.1, the differences between the expenditures shown in the 2012 LTCP and those provided in the 2014-2018 RRA are not the result of reductions in overall forecast capital expenditures, but are related rather to shifts in the timing of certain projects, as well as the exclusion of overheads and AFUDC from the capital expenditures shown in Table C5-4. The proposed projects for the PBR period are based on the "2012 LTCP approved" projects. As a prudent utility operator, FBC reviews all projects and programs to ensure the level and timing of forecast expenditures remains appropriate.

156.0 Reference: Exhibit B-1, pp. 189-192

Generation Sustainment Capital

Building Code or Regulatory Expenditures

156.1 Please explain why the following sustaining capital expenditures are not considered as either building code or regulatory expenditures (Z-Factor):

- Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels,
- All Plants Fire Safety,
- All Plants Safety and Security,
- Dam Safety Instrumentation.

Response:

All generation safety and sustaining capital expenditures to meet existing building codes and regulatory requirements are part of the base PBR Plan capital expenditures. The forecast expenditures associated with meeting these requirements are based on FBC's experience and knowledge, and are to a certain extent controllable. Exogenous factors, or Z-Factors, would apply to any changes or additions to the applicable codes and/or regulatory requirements not within FBC management control that result in unforeseen incremental expenditures. Please also refer to the response to BCUC IR 1.113.2.

157.0 Reference: Exhibit B-1, pp. 193-196

Station Sustainment Capital

Code or Regulatory Expenditures

157.1 Please explain why the following sustaining capital expenditures are not considered as either code or regulatory expenditures (Z-Factor):

- Oil Containment,
- Ground Grid Upgrades.

Response:

There is no recent change to codes or regulatory legislation that has resulted in FBC proposing these projects. Hence, the sustaining capital expenditures for Oil Containment and Ground Grid Upgrades are not driven by code or regulatory requirements, but rather are undertaken as a matter of Good Utility Practice. This is consistent with all of FBC's sustaining capital expenditures as discussed in Section C5 of the Application.

158.0 Reference: Exhibit B-1, p. 202

Distribution Line Sustainment Capital

Code or Regulatory Expenditures

158.1 Please explain why the following sustaining capital expenditures are not considered as either code or regulatory expenditures (Z-Factor):

- Environmental Compliance - Distribution Equipment (PCB).

Response:

Z-Factors are intended to address non-controllable and unforeseeable costs, including those costs that may be driven by unforeseen legislative changes. With respect to the legislative changes affecting distribution equipment containing PCBs, FBC has been aware of these changes for a number of years. Further, the legislative changes also provide an in-service exemption until 2025 for distribution equipment containing PCBs. Based on these factors, FBC has a certain amount of control over the level of costs associated with remediation of any PCB contaminated distribution equipment. As such, the Company believes that inclusion of the Environmental Compliance – Distribution Equipment (PCB) under the proposed PBR capital formula is appropriate.

Any future changes to legislation that result in non-controllable and unforeseen costs related to PCB management may need to be treated as Z-Factors.

159.0 Reference: Exhibit B-1, p. 204

ArcFM Feeder System Audit

159.1 Was this $337,000 expenditure previously included in the acquisition price for the City of Kelowna distribution system? If not, please explain why not.

Response:

No, the referenced $337 thousand expenditure was not included in the acquisition price for the City of Kelowna distribution system. The acquisition price for the City of Kelowna distribution system included historical and forecast costs to Q1 2013 (please refer to the table below, reproduced from information found at page 15 and 16 of Appendix A to Order C-4-13). The ArcFM Feeder System Audit of $337 thousand is a 2014 capital cost element (please refer to Table 1A-1, Appendix-E, Vol. 1 of the 2014 – 2018 RRA Filing) and hence was not included in the acquisition price for the City of Kelowna distribution system.

Order C-4-13:	
NBV 2011	29,200
CWIP 2011	3,700
Plants 2012	4,100
Depreciation 2011	(1,100)
Plants Q1 2013	1,400
Depreciation Q1 2013	(300)
Land	700
Sub Total - 1:	**37,700**
Estimated Property Transfer Tax on Land	66
Grand Total:	**37,766**

160.0 Reference: Exhibit B-1, p. 206

Backbone Transport Technology Migration

160.1 Please provide the cost for this item.

Response:

The unloaded estimate cost for this project is $1,701 thousand.

160.2 Please discuss if this item a non-recurring cost item. Could this item be considered a Z-Factor item?

Response:

The Backbone Transport Technology Migration is not a non-recurring cost item as technological obsolescence is expected to occur periodically. Given that Z-Factors are intended to address non-controllable and unforeseeable costs, FBC would not consider it appropriate to classify this project as a Z-Factor item.

161.0 Reference: Exhibit B-1, p. 206

SCADA and MRS Systems Sustainment

161.1 Please provide the costs for the MRS System Sustainment program.

Response:

Unloaded expenditures of approximately $1.1 million are budgeted for the MRS System Sustainment Program over the term of the 2014 - 2018 PBR period.

161.2 Please discuss whether the MRS System Sustainment program would be considered as a Z-Factor item. Why or why not?

Response:

The costs associated with the MRS System Sustainment program have been forecast based on the Company's experience with MRS, and are included in Base Capital, hence they do not meet the definition of a Z-Factor item. However, if during the term of the PBR there were cost increases arising from changes in MRS requirements, they may be considered a Z-Factor as those cost increases are not controllable.

162.0 Reference: Exhibit B-1, p. 207

Growth Capital Overview

Table C5-5

162.1 Please separate the row "Transmission, Station and Telecommunications" into a new expanded table having rows "Transmission", "Stations", "Telecommunications", and "Distribution."

Response:

Please see the table below which provides the requested breakdown:

Growth Capital ($000s)	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Transmission	332	135	-	-	-	676
Stations	-	3,051	3,190	-	293	2,252
Telecommunications	-	-	-	-	-	-
Distribution	20,306	15,102	14,732	15,589	15,764	16,916
Total	**20,638**	**18,289**	**17,922**	**15,589**	**16,057**	**19,844**

162.2 Please discuss how the formula using the incremental change in average customers would be applicable to each of the above elements given the residential, commercial, industrial, wholesale, etc. electric load forecasts in section C1 of the Application.

Response:

FBC's proposed Growth Capital Projects are necessary to provide safe and reliable service to customers based on an analysis of actual and forecast demand. B&V note that in electric utilities the TFP unit of output is measured by both the number of customers served and the capacity required to deliver the kWhs of electricity to customers. In fact, growth capital is driven by both customers and 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 the incremental change in average customers adds new capacity to the system.

163.0 Reference: Exhibit B-1, p. 208

Transmission and Station Growth Capital

MRS Projects

163.1 The following projects appear to be driven by MRS requirements: 42 Line Meshed Operation between Huth and Oliver, Voltage Support in South Okanagan/Boundary during Contingency. Please explain whether these projects would be considered to a Z-Factor item.

Response:

These projects are driven by FBC planning standards. FBC notes that these internal criteria were developed many years prior to the formal adoption of the BC MRS; were based on what was considered Good Utility Practice within the WECC region; and have been referenced and accepted in numerous projects previously approved by the Commission.

Although these projects are required for compliance with the BC MRS, even in the absence of the BC MRS, FBC would still have proposed these transmission reinforcements. Since the proposed projects are consistent with ongoing upgrades required to meet historical FBC system planning practices, FBC does not consider these projects to be a Z-Factor item.

164.0 Reference: Exhibit B-1, p. 208

Transmission and Station Growth Capital

Reconductor 52 and 53 Lines

FBC states "Such load shedding is not consistent with FBC planning standards for transmission system performance which do not permit loss or curtailment of load after a single contingency."

164.1 Please explain if this project is required by MRS standards? Could this item be considered a Z-Factor item?

Response:

Yes, this project is required for compliance with MRS standards. However, this project is also driven by FBC planning standards, as noted in the preamble. FBC notes that these internal criteria were developed many years prior to the formal adoption of the BC MRS; were based on what was considered Good Utility Practice within the WECC region; and have been referenced and accepted in numerous projects previously approved by the Commission.

Even in the absence of the BC MRS, FBC would still have proposed this transmission reinforcement. Since the proposed project is consistent with ongoing upgrades required to meet historical FBC system planning practices, FBC does not consider this project to be a Z-Factor item.

165.0 Reference: Exhibit B-1, p. 213

Distribution Growth Capital

New Connects System Wide

165.1 Please provide FBC's gross average cost for providing a new connection. State your assumptions.

<u>Response:</u>

Based on forecast expenditures (loaded) of $16.070 million for new connects in 2013 (as shown in Table 1-A-1 from Tab E of Exhibit B-1), and forecast additions of approximately 840 customers in 2013 (Table C1-3, Section C1, adjusted for the addition of approximately 14,460 City of Kelowna customers), the gross average cost for 2013 of providing a new connection is approximately $19 thousand per customer. This estimate is based on the assumption that all new customers require a primary system extension in order to receive service.

165.2 Please provide the customer's cost for obtaining a new connection.

<u>Response:</u>

Based on a 2013 forecast for contributions in aid of construction (CIAC) of approximately $5.2 million (Table 1-D from Tab E of Exhibit B-1), and 2013 forecast additions of approximately 840 customers as noted in the response to BCUC IR 1.165.1 above, the customer's cost of obtaining a new connection is approximately $6 thousand per connection. Again, this estimate is premised on the assumption that all new customers require a primary system extension in order to receive service.

165.2.1 Please explain if there will be any impact to the new-connection cost from the recently approved AMI project.

<u>Response:</u>

It is expected that the AMI system will service the majority of potential new connects, and thus have no impact to the new connection cost. However, there may be instances where a new connect will require an extension of the AMI communications network in order to maintain connectivity of the RF-LAN to the new meter. Where the capital costs of extending the communications network can be directly attributed to the addition of a new connect (for example, the need for a range extender), such costs will be included in the overall determination of the costs, including any applicable CIAC, required to construct an extension to serve the new customer.

166.0 Reference: Exhibit B-1, p. 214

Distribution Growth Capital

Fault Indicator Installation

166.1 Please provide the estimated cost for the fault indicator installation project.

<u>Response:</u>

The unloaded estimated cost to retrofit fault indicators on underground equipment in the former City of Kelowna service territory is estimated at approximately $0.7 million.

166.2 Please discuss the merits of providing fault indicators versus waiting for the AMI Outage Management System.

<u>Response:</u>

Although the AMI Outage Management System (OMS) would identify the customers affected by an outage on an underground distribution feeder, the OMS would not generally provide all the information required to help isolate a fault along an underground feeder. Unlike overhead distribution infrastructure, underground distribution infrastructure cannot be visually inspected to determine the geographic location of a fault. Further, due to the nature of underground distribution, groups of customers are typically supplied via a series of separate segments of underground cable. Fault indicators are able to identity exactly which cable segment has faulted; an OMS is not able to provide this level of fault localization.

The determination of the geographic location of an underground fault is important as the operation of the installed protective devices in response to a fault event will typically result in an outage whose customer impact can only be minimized once the fault is located and isolated. The visual confirmation provided by fault indicators is critical to ensuring that a particular underground fault is located and isolated in a timely manner. Underground fault indicators help improve system restoration times, reduce operating costs, increase safety, and decrease the risk of equipment damage related to fault chasing procedures.

166.3 If the AMI Outage Management System goes ahead, what would be the difference in cost of the two systems?

Response:

The cost of implementing an Outage Management System for the entire FortisBC electric network is estimated at an unloaded cost of approximately $0.5 million. This represents a difference of approximately $0.2 million as compared to the estimated unloaded costs of retrofitting fault indicators on existing underground equipment in the former CoK service area as provided in the response to BCUC IR 1.166.1 above. However, it is important to note that underground fault indicators will provide information that is not available through an AMI Outage Management System. The information provided by underground fault indicators is necessary for the reasons noted in the response to BCUC IR 1.166.2 above, as well as in section 5.5.3.5 from Tab C of Exhibit B-1.

166.3.1 Would the fault indicator system still be useful if the Outage Management System went ahead?

Response:

Yes. Please refer to the response to BCUC IR 1.166.2.

167.0 Reference: Exhibit B-1, p. 223

Other Capital

Buildings

FBC states, "As per the FBC Access Control Policy and the BC Mandatory Reliability Standards, FBC has a requirement to provide controlled access to building sites to ensure the security and safety of FBC employees and assets."

167.1 Please provide the estimated cost of meeting the FBC Access Control Policy.

Response:

Access control is the control of persons, vehicles and material through a facility. In the aspect of security, access control utilizes a combination of electronic and hardware systems and specialized procedures to control and monitor movement into, out of and within restricted areas and is integrated with the intrusion activity.

FBC Facilities current electronic systems were installed pre-2000 and no longer receive vendor support. With the age of the application, operating system and hardware, there is a risk of no fallback it the event of a critical failure. The estimated cost for replacement is $500 thousand.

FBC has put additional funding in future years to integrate camera and digital video recording for specific problematic sites. The costs are estimated at $100 thousand.

167.2 Please provide the estimated cost of meeting the BC MRS standards.

Response:

There are no incremental costs associated with meeting the BC MRS standards as the existing access control system already allows FBC to meet the applicable BC MRS requirements.

168.0 Reference: Exhibit B-1, p. 224

Tools and Equipment

FBC states "The Tools and Equipment budget is used to purchase and/or replace tools that have a value greater than $1,000."

168.1 Please explain why the value of "Tools and Equipment" of $1,000 or greater is not escalated each year.

Response:

The $1 thousand limit is in reference to the Company's Capitalization Policy that requires tool and equipment expenditures to be in excess of $1 thousand before they can be capitalized and is meant to be viewed at a macro level. The Company does not believe an annual adjustment to this threshold is necessary, but does adjust the level on occasion when the cumulative compound inflation has a material impact (e.g. a 50 percent increase). This level is established only for administrative ease.

169.0 Reference: Exhibit B-1, p. 226

Advanced Metering Infrastructure

169.1 Please explain if the sustaining capital expenditures shown are gross or net.

<u>Response:</u>

As there are no CIAC associated with the sustaining capital expenditures for the AMI project, no distinction between gross and net is applicable.

170.0 Reference: Exhibit B-1, p. 207

Sustainment Capital Overview –

Table C5-6 Forecast Growth Capital Expenditures

170.1 Please explain the differences in forecasted growth capital expenditures between the PBR forecast and the 2012 LTCP expenditures in Appendix J (2012-2013 RRA and ISP Application) for the forecasted years 2014-2018 that amounted to a shortfall of $267 million. See table provided below.

	2013	2014	2015	2016	2017	2018	2014-2018
	Base	Forecast	Forecast	Forecast	Forecast	Forecast	Total
Growth Capital							
Transmission, Station & Telecommunications	332	3,187	3,190	0	293	2,928	9,598
Distribution	20,306	15,102	14,732	15,589	15,764	16,916	78,103
Total Growth Capital	20,638	18,289	17,922	15,589	16,057	19,844	87,701
2012 LTCP (Appendix J - Growth Capital)							
Transmission, Station & Telecommunications	11396	17287	28703	19051	51293	63474	179,808
Distribution	13759	16300	14320	19172	13744	15770	79,306
Total Growth Capital	25155	33587	43023	38223	65037	79244	259,114
Growth Capital (PBR-LTCP)							
Transmission, Station & Telecommunications	(11,064)	(14,100)	(25,513)	(19,051)	(51,000)	(60,546)	(170,210)
Distribution	11,459	(2,185)	(12,805)	324	(35,529)	(46,558)	(96,753)
Total Growth Capital	395	(16,285)	(38,318)	(18,727)	(86,529)	(107,104)	(266,963)

(Adapted from data provided in Exhibit B-1 and App. J of 2012-2013 RRA and ISP Application)

Response:

FBC notes that the total difference of $267 million identified in the question incorrectly includes approximately $96.8 million attributed to Distribution. Based on the information provided in the table above, the difference in forecast Distribution growth expenditures between the 2012 LTCP and the 2014-2018 RRA amounts to approximately $1.2 million (not $96.8 million), resulting in an overall difference of approximately $171 million as opposed to $267 million identified in the question. The $171 million difference can be reconciled as follows:

- The expenditures shown in the 2012 LTCP include overheads (capitalized and direct) and AFUDC, whereas the capital expenditures in Table C5-6 are unloaded and do not include AFUDC. With loadings and AFUDC excluded from the 2012 LTCP, the difference between the 2012 LTCP and Table C5-5 becomes approximately $128 million.

- Appendix J of the 2012 LTCP included expenditures related to the Kelowna Bulk Capacity Addition, the Meshing Kelowna Loop, the Grand Forks Transformer Addition, and the Central Okanagan Substation. As these are considered Major Projects (CPCNs) for the purposes of the 2014 – 2018 PBR, they are not included in Table C5-6. Excluding the expenditures related to these Major Projects from the 2012 LTCP narrows the difference between the growth expenditures presented in the 2012 LTCP and those shown on Table C5-6 for the 2014 – 2018 period to approximately $78 million.

This remaining difference of approximately $78 million between the 2014 – 2018 expenditures presented in the 2012 LTCP as compared to Table C5-5 is primarily the result of shifts in the timing of a number of projects, updates to forecast expenditures for the PBR period, as well as the addition of certain Transmission, Stations, and Distribution Growth projects (not identified in the 2012 LTCP) related to the acquisition of the City of Kelowna distribution assets.

Project originally shown in the 2012 LTCP (for 2014 – 2018) that have since been delayed beyond the 2014 – 2018 PBR period include:

- Meshing Kelowna Loop;
- Beaver Valley South Solution;
- RG Anderson Distribution Transformer Upgrade;
- DG Bell Static VAR Compensator;
- FA Lee Distribution Transformer Addition; and
- Enterprise Substation.

The reduction in expenditures of approximately $81 million related to the projects identified above is offset by an increase in forecast expenditures of approximately $3 million related to the addition of certain projects necessitated by the acquisition of the City of Kelowna distribution assets. These projects were not previously identified in the 2012 LTCP. These projects include:

- Spall Breaker House Reconfiguration;
- Saucier Substation Project and Metering Upgrade; and
- Fault Indicator Installation.

170.2 Please explain how this reduction in expenditures will affect the “2012 LTCP approved” operation of the utility.

Response:

As explained in the response to BCUC IR 1.170.1, the differences between the expenditures shown in the 2012 LTCP and those provided in the 2014-2018 RRA are not the result of reductions in overall forecast capital expenditures, but are related rather to shifts in the timing of certain projects, as well as the exclusion of overheads and AFUDC from the capital expenditures shown in Table C5-6. The proposed projects for the PBR period are based on the “2012 LTCP approved” projects. As a prudent utility operator, FBC reviews all projects and programs to ensure the level and timing of forecast expenditures remains appropriate.

171.0 Reference: Exhibit B-1, p. 207

Sustainment Capital Overview –

Table C5-6 Forecast Other Capital Expenditures

171.1 Please explain the differences in forecasted other (general plant) capital expenditures between the PBR forecast and the 2012 LTCP expenditures in Appendix J (2012-2013 RRA and ISP Application) for the forecasted years 2014-2018 that amounted to a shortfall of $59 million. See table provided below.

Response:

FBC notes that the table referenced in the question was not provided. As such, FBC has prepared the following table comparing forecast expenditures from the 2012 LTCP with the forecasts provided as part of the 2014 – 2018 RRA for Other (General) Capital:

($000s)	**2014**	**2015**	**2016**	**2017**	**2018**	**2014 – 2018 Total**
Other Capital (PBR – Table C5-6)	26,078	28,449	13,738	10,247	10,162	**88,674**
Other Capital (2012 LTCP – Appendix J)	19,920	9,423	9,885	9,881	10,217	**59,326**
Other Capital (PBR-LTCP)	**6,158**	**19,026**	**3,853**	**366**	**(55)**	**29,348**

Based on the table above, the difference between the expenditures shown in the 2012 LTCP and those included as part of the 2014 – 2018 RRA amounts to an increase of approximately $29 million, and not a shortfall of $59 million as referenced in the question. Because the expenditures shown in the 2012 LTCP included overheads (capitalized and direct) and AFUDC, whereas the capital expenditures in Table C5-6 are unloaded and do not include AFUDC, this difference increases to approximately $37 million when loadings and AFUDC are excluded from the 2012 LTCP.

This difference of $37 million in forecast expenditures for the 2014 – 2018 period is primarily the result of shifts in the timing of a number of projects as well as updates to forecast expenditures for the PBR period, including:

- The timing of the expenditures for the Advanced Metering Infrastructure Project have shifted as compared to the forecast originally provided as part of the 2012 LTCP. As a result, additional expenditures of approximately $31 million are reflected in the 2014 – 2018 PBR forecast as compared to the 2012 LTCP (majority of AMI expenditures originally forecast in 2013); and

- The 2014 – 2018 PBR forecast include expenditures of approximately $6.5 million related to the Business Technology Transformation project. This project was not previously identified in the 2012 LTCP.

H. FINANCING AND ACCOUNTING POLICIES

172.0 Reference: Exhibit B-1, p. 232-237; Appendix E, Schedule 5

Financing Expenses

FBC requests to establish an interest expense variance, rate base deferral account to capture the impact on interest expense of short term and long term interest rate variances, as well as variances associated with the volume and timing of issuing debt.

FBC also states that the potential gains and losses on forecasting interest expense are affected by global economic factors and market conditions that are beyond the Company's control.

172.1 Please provide FBC's forecast interest expenses and actual interest expense for each of the last ten years broken down into long term and short term debt. Calculate the variances from year to year.

Response:

The following tables provide the historical interest expense variances.

(in $000s)

2012	Decision*	Actual	Variance
Long Term interest expense	38,422	38,422	-
Short Term interest expense	1,760	264	1,496
Total interest expense	40,182	38,686	1,496

2011	Decision*	Actual	Variance
Long Term interest expense	39,275	38,664	611
Short Term interest expense	1,231	228	1,003
Total interest expense	40,506	38,892	1,614

2010	Decision*	Actual	Variance
Long Term interest expense	34,880	34,174	706
Short Term interest expense	1,902	964	938
Total interest expense	36,782	35,138	1,644

2009	Decision*	Actual	Variance
Long Term interest expense	34,112	33,363	749
Short Term interest expense	691	48	643
Total interest expense	34,803	33,411	1,392

2008	Decision*	Actual	Variance
Long Term interest expense	31,126	31,116	10
Short Term interest expense	636	(953)	1,589
Total interest expense	31,762	30,163	1,599

*Decision is the forecast that was approved for rate-setting purposes.

(in $000s)

2007	Decision*	Actual	Variance
Long Term interest expense	25,997	28,202	(2,205)
Short Term interest expense	2,870	529	2,341
Total interest expense	28,867	28,731	136

2006	Decision*	Actual	Variance
Long Term interest expense	25,096	25,062	34
Short Term interest expense	1,427	1,050	377
Total interest expense	26,523	26,112	411

2005	Decision*	Actual	Variance
Long Term interest expense	21,497	20,278	1,219
Short Term interest expense	1,304	2,111	(807)
Total interest expense	22,801	22,389	412

2004	Decision*	Actual	Variance
Long Term interest expense	11,993	12,637	(644)
Short Term interest expense	9,036	6,396	2,640
Total interest expense	21,029	19,033	1,996

2003	Decision*	Actual	Variance
Long Term interest expense	12,076	12,087	(11)
Short Term interest expense	7,748	7,033	715
Total interest expense	19,824	19,120	704

2002	Decision*	Actual	Variance
Long Term interest expense	8,789	10,283	(1,494)
Short Term interest expense	8,047	4,917	3,130
Total interest expense	16,836	15,200	1,636

*Decision is the forecast that was approved for rate-setting purposes.

172.2 Please discuss whether these variances of 'gains and losses' would generally balance out over time? Why or why not?

Response:

No, gains and losses between actual and forecast occur independently of each other each year and therefore do not balance out over time. These variances between forecast and actual interest expense are driven by what happens with global economic factors and market conditions between a point in time forecast and what actually occurs throughout the year. While FortisBC will annually update its interest expense forecast using third party publications available at the time of forecasting as part of the Company's subsequent RRA filing and Annual Reviews, there is still in excess of a year for which interest expense could be higher or lower than what was forecast at a point in time for setting rates.

172.3 Please confirm that FBC's proportion of LTD is approximately 98 percent versus STD, approximately 2 percent, of its total debt capital.

Response:

For 2013 Projection, FortisBC's proportion of long-term debt and short-term debt balances are forecast to be approximately 95 per cent and 5 per cent, respectively.

For 2014 Forecast, FortisBC's proportion of long-term debt and short-term debt balances are forecast to be approximately 100% and nil, respectively.

While these proportions demonstrate that all, or almost all, debt balances used to finance 60 per cent of rate base for 2013 and 2014 are forecast to be comprised of long-term debt instruments, the interest expense itself can vary significantly as a result of variances on the forecast coupon rate at a point in time versus the actual coupon rate at the time of issuance.

172.4 Please confirm that for each specific long term debenture, the debt coupon rate or forecast coupon rate is generally known at the time the debenture is issued.

Response:

Confirmed. The actual debt coupon rate is determined at the time when the new issue is offered and priced in the market, which is typically 3 business days before the debenture is issued to debt investors. While FBC provides a forecasted coupon rate for setting customer rates, market conditions beyond the Company's control, can cause a variance from the point in time forecast rate to the actual coupon rate at date of issue.

172.4.1 Do the coupon rates or forecast coupon rate change during the term of the debenture?

Response:

The actual coupon rate is set at the time of issue and is typically fixed over the term of the debenture. FBC is not sure what is meant in the question by the term "forecast coupon rate" so is not clear on what is being asked. A forecast coupon rate would be simply a point in time forecast of what the actual coupon rate may be for a planned debenture issue. To clarify, just because FBC will forecast a coupon rate for a future issuance, the actual rate is unknown until the date of issue.

173.0 Reference: Exhibit B-1, p. 238

Taxes

"For the purposes of the forecasts in this Application, FBC has used the same corporate tax rate forecast of 25 percent for 2015 through 2018."

"On June 27, 2013, the BC government reintroduced legislation to increase the general corporate income tax rate by 1 percent effective April 1, 2013, however it is not yet enacted."

173.1 Please explain why FBC did not include the income tax increase of 1 percent in 2013? What is the likelihood that this increase will not be enacted by the government? Please discuss.

Response:

FBC did not include the 1 percent increase in corporate income taxes as the change was not enacted at the time of filing the 2014-18 PBR Application. FBC will file an Evidentiary Update to the Application on October 18, 2013, and will be including this 1 percent corporate tax rate increase which was enacted on July 25, 2013, in its forecasted income tax expense.

For the 0.75 percent increase effective for 2013, FBC will defer the estimated approximately $0.3 million effect as part of the HST Removal or Reform Variance Deferral Account which was approved pursuant to G-110-12 since the corporate tax rate increase was reintroduced to balance the 2013/14 BC provincial budget as a result of eliminating HST. As documented in the 2012-13 RRA response to BCUC IR 2.27.1 the HST Removal or Reform Variance Deferral Accounts was to be established to include "the outcomes of the HST referendum and the resulting BC provincial government decisions and legislative changes", therefore the inclusion of the effects of the 1 percent corporate income tax increase meet the criteria for inclusion in the HST Removal or Reform Variance Deferral Account.

174.0 Reference: Exhibit B-1, p. 244-246

US GAAP and Securities and Exchange Commission Extension

FBC states "Currently, FBC has an exemption from the Ontario Securities Commission (OSC)…The exemption was received in 2011 and covers the period beginning January 1, 2012 and ending December 31, 2014. FBC intends to continue using US GAAP for external financial reporting purposes beyond 2014 by either obtaining an additional OSC exemption or by becoming an SEC Issuer. FBC, in conjunction with Fortis Inc. and its subsidiaries, intends to file a request by December 31, 2013, that the OSC extend the exemption beyond 2014. If the OSC does not agree to an extension then FBC, in conjunction with Fortis Inc. and its subsidiaries, will begin the process of becoming an SEC Issuer in order to continue preparing external financial statements in accordance with US GAAP for 2015 and beyond." (p. 244)

174.1 What is FBC's opinion of the likelihood that the OSC would agree to an extension?

Response:

FBC, in conjunction with its parent company Fortis Inc. and its subsidiaries, has just begun the process of requesting an extension from the OSC for the exemption to extend beyond 2014. At this stage it is too early to assess whether the OSC would agree to the extension or not.

174.2 Please generally discuss the operational and financial implications of FBC potentially becoming an SEC Issuer. What are the initial adoption costs and ongoing costs to becoming an SEC issuer? Will there be a legal status change for FBC?

Response:

To become an SEC Issuer FBC would be required to list an existing investment grade, non-convertible debt instrument on the New York Stock Exchange (NYSE) and file a registration statement with the SEC. As an SEC Issuer FBC would continue to prepare and file financial statements in accordance with US GAAP for interim and annual periods beginning January 1, 2015, but would also fall under any applicable securities requirements specific to the SEC and NYSE, which have been summarized below.

If FBC were to become an SEC Issuer, there would be additional compliance and reporting requirements that may include, but not be limited to, the following:

a. The initial registration statement, as well as subsequent annual reports, would be filed on either a Form 40-F or a Form 20-F. FBC would also be required to furnish the SEC with current reports on Form 6-K.

b. FBC would be required to comply with the rules of the NYSE which include, but are not limited to, most of the corporate governance requirements of the NYSE, audit committee independence rules, annual certification requirements confirming compliance with such rules and disclosure on how Canadian governance rules differ from the U.S. rules.

c. FBC may be subject to most of the Sarbanes-Oxley (SOX) requirements including, but not limited to, the requirement that certain officers certify the annual report and the rules relating to disclosure controls and procedures and internal control over financial reporting, and potentially an attestation report of the Company's independent auditor on the issuer's internal controls. Fortis Inc. would be subject to Sarbanes-Oxley so as a result, FBC would be required to be included in that testing as it is a material subsidiary.

Additionally, FBC could possibly be subject to other acts and requirements (such as XBRL reporting) as an SEC Issuer.

Even with the additional compliance and reporting requirements that would exist if FBC were to become an SEC Issuer, the continuation of reporting under US GAAP, which allows regulated entities to recognized regulatory assets and liabilities under ASC 980, *Regulated Operations*, is a better option than reporting under IFRS which currently does not have existing standards that permit similar treatment.

At this point in time, based on FBC's understanding of the SEC registration process, the estimated one-time costs FBC would expect to incur during the process of becoming an SEC Issuer are approximately $240 thousand. The incremental ongoing annual costs that FBC expects to incur as an SEC Issuer would be approximately $100 thousand.

If FBC pursues becoming an SEC Issuer, an update on the process and the forecasted costs of becoming an SEC Issuer will be provided as part of a stand-alone application to the BCUC made by the FBC Utilities.

No, there will not be a legal status change for FBC.

174.2.1 Please discuss who will bear the incremental costs of FBC potentially becoming SEC Issuer and why?

Response:

The incremental costs of FBC potentially becoming an SEC Issuer would be borne by ratepayers because the costs would be prudent and reasonably incurred costs of doing business. The incremental costs are similar to costs FBC currently incurs, such as filing costs related to debt issuances and audit fees, which are currently borne by ratepayers. These incremental SEC costs could be recovered similarly to those approved pursuant to Order G-117-11 whereby FBC recorded one-time conversion costs associated with the adoption of US GAAP in a rate base deferral account, for recovery from customers in 2012 and 2013. FBC becoming an SEC Issuer will allow FBC to continue to report externally and for regulatory purposes under US GAAP.

The adoption of US GAAP for regulatory purposes beginning in 2012 has allowed for the continuation of both transparency and comparability between regulatory and external financial reporting since US GAAP allows for regulated entities to recognize regulatory assets and liabilities under ASC 980, *Regulated Operations*, while IFRS does not currently have existing standards that permit similar treatment.

Additionally, FBC believes that the same set of accounting principles should be used for regulatory purposes as what is used for external financial reporting purposes so that the underlying economic substance of the Company's operations is appropriately reflected. If the BCUC set accounting requirements that differed from what was used to account for the same transaction for external financial reporting purposes, this would result in the Company having to maintain two sets of accounting records which would result in a significant amount of work and cost to the Company and customers and decrease the relevance of the external financial statements. Furthermore, adopting the same set of accounting principles for financial reporting and regulatory reporting will enhance both transparency and comparability between regulatory and external financial reporting.

174.2.2 What actions are required to comply with the Sarbanes-Oxley Act? What are the estimated annual costs associated with these actions?

Response:

As mentioned in the response to BCUC IR 1.174.2, FBC may be subject to most of the SOX requirements including, but not limited to, the requirement that certain officers certify the annual report and the rules relating to disclosure controls and procedures and internal control over financial reporting, and potentially an attestation report of the Company's independent auditor on the issuer's internal controls. Fortis Inc. would be subject to Sarbanes-Oxley so as a result, FBC would be required to be included in that testing as it is a material subsidiary.

At this point in time, based on FBC's understanding of the SOX requirements, the estimated ongoing annual costs that FBC expects to incur with respect to SOX requirements would be approximately $50 thousand.

If FBC pursues becoming an SEC Issuer, an update on the process and the forecasted costs of becoming an SEC Issuer will be provided as part of a stand-alone application to the BCUC made by the FBC Utilities.

Commission Order G-117-11, which approved the adoption of US GAAP by FBC for regulatory accounting and reporting purposes, also required an annual reconciliation from US GAAP back to Canadian GAAP. FBC has provided this reconciliation in its 2012 BCUC Annual Report but is now requesting to discontinue this US GAAP to Canadian GAAP reconciliation starting with the 2013 BCUC Annual Report. FBC indicates 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.

174.3 How much time is required to prepare this US GAAP to Canadian GAAP reconciliation?

Response:

FBC estimates approximately one week was spent preparing and reviewing the US GAAP to pre-changeover Canadian GAAP reconciliation for 2012. Since pre-changeover Canadian GAAP has ceased to exist, the reconciliation for items such as pension and OPEB will magnify on a prospective basis. Therefore, continuing to prepare this reconciliation is expected to not only increase the future preparation and review time, but also increase the external actuarial costs.

174.4 In lieu of this reconciliation, would FBC be willing to commit to filing to the Commission any future changes in accounting policy or any material impact from its interpretation of US GAAP?

Response:

FBC would be willing to file with the Commission any future accounting policy changes or any material impact from its interpretation of US GAAP that would have an impact on setting customer rates. While there are always changes and developments that are occurring with US GAAP, not all such changes in accounting policy will have an impact to FBC. As a result, FBC would agree to provide and communicate accounting policy changes consistent with what was provided during the previous PBR term.

174.5 If it becomes apparent in the future that becoming an SEC Issuer would be too costly for FBC and the industry still does not have any certainty on rate-regulated accounting issues from the IASB, what other options would FBC entertain?

Response:

If the only way that FBC could continue to use US GAAP would be to become an SEC Issuer, then there would be no other options that FBC would entertain. This is because the adoption of US GAAP for regulatory purposes beginning in 2012 has allowed for the continuation of both transparency and comparability between regulatory and external financial reporting since US GAAP allows for regulated entities to recognize regulatory assets and liabilities under ASC 980, *Regulated Operations*, while IFRS does not currently have existing standards that permit similar treatment. Please refer to the response to BCUC IR 1.174.2.1 as to why the continuation of US GAAP is in the best interest of FBC and why adopting IFRS is currently not an appropriate option.

If FBC pursues becoming an SEC Issuer, an update on the process and the forecasted costs of becoming an SEC Issuer will be provided as part of a stand-alone application to the BCUC made by the FBC Utilities.

175.0 Reference: Exhibit B-1, p. 245; Order G-117-11

Exhibit A2-2, Appendix A of FBC's 2012 BCUC Annual Report

US GAAP Reconciliation

"In Order G-117-11 the BCUC approved the adoption of US GAAP by FBC for regulatory accounting and reporting purposes effective January 1, 2012. As part of that order, the Commission requested an annual reconciliation from US GAAP back to Canadian GAAP. FBC has provided this reconciliation in FBC's 2012 BCUC Annual Report Appendix A." (Exhibit B-1, p. 245)

Order G-117-11 notes the following: "Each of Fortis BC Utilities' entities adopting US GAAP shall prepare a reconciliation of amounts reported for **regulatory accounting** to those amounts that would otherwise be reported under 2011 Canadian GAAP. This reconciliation should be included in annual reports and revenue requirements applications up to December 31, 2014." [Emphasis added]

175.1 Please confirm, or explain otherwise, that Exhibit A2-2, filed in FBC's 2012 BCUC Annual Report, reconciles 2012 amounts reported for regulatory accounting under US GAAP to amounts that would have been reported for regulatory accounting under Canadian GAAP.

Response:

FBC confirms that Exhibit A2-2, which is Appendix A as filed in FBC's 2012 BCUC Annual Report, reconciles 2012 amounts reported for regulatory accounting under US GAAP to (1) amounts that would have been reported under pre-changeover Canadian GAAP, which is then reconciled to (2) amounts that are reported for FBC's regulated business. This reconciliation is also filed in Appendix F5 to FBC's 2014-2018 PBR Application.

Note that as discussed in Tab 2-Accounting Policy of FBC's 2012-2013 RRA and Section 2 - Background of the FBC Utilities Application to Adopt US GAAP, beginning in 2012 pre-changeover Canadian GAAP was withdrawn by Canadian standard setters and ceased to exist as a financial reporting option.

175.1.1 If the preceding IR is not confirmed, please provide the reconciliation of 2012 amounts reported for regulatory accounting under US GAAP to amounts that would have been reported for regulatory accounting under Canadian GAAP.

Response:

Not applicable. Please refer to the response to BCUC IR 1.175.1.

175.1.2 Please provide the amount and a description of any reconciling items between amounts reported for regulatory accounting under US GAAP to those amounts that would otherwise be reported under Canadian GAAP in 2012.

Response:

Exhibit A2-2, which is Appendix A as filed in FBC's 2012 BCUC Annual Report, contains the amounts and descriptions of each adjustment on page 39 titled "Reconciliation of Balance Sheet". Note that there are no adjustments to the statement of earnings as a result of adopting US GAAP, as indicated on page 36 "Statement of Earnings, Corporate and Regulatory" under the column "US GAAP Adjustment".

Further descriptions of the adjustments that were made upon transition to US GAAP are included in Appendix E-Accounting Changes: US GAAP to FBC's 2012-2013 Revenue Requirements Application.

175.1.3 Please discuss if FBC anticipates that the reconciling items for 2013 and beyond will vary significantly from those reported in 2012 and explain why.

Response:

FBC does anticipate the reconciling items beyond 2013 will eventually vary significantly from those reported in 2012. While most of the reconciling items reported for 2012 are likely to continue to exist, additional future reconciling items would be expected to occur as FBC enters into new transactions and as accounting guidance continues to change. It will become increasingly difficult for FBC to quantify the amount of any incremental reconciling items as FortisBC no longer maintains specific accounting records in compliance with pre-changeover 2011 Canadian GAAP since they are not used for any other reporting purpose

Note that continuing to prepare a reconciliation to pre-changeover Canadian GAAP could be misleading in identifying true differences that would exist if pre-changeover Canadian GAAP had continued to be a financial reporting option. As discussed in Tab 2-Accounting Policy of FBC's 2012-2013 Revenue Requirements Application and Section 2-Background of the FBC Utilities Application to Adopt US GAAP, beginning in 2012 pre-changeover Canadian GAAP was withdrawn by Canadian standard setters and ceased to exist as a financial reporting option. Therefore, to the extent that a difference from pre-changeover Canadian GAAP arises from a change in accounting guidance by US standard setters, it would be difficult to determine whether a similar accounting guidance change would have occurred under Canadian GAAP if this financial reporting option had continued to exist. Currently, many emerging issues that result in new accounting guidance are jointly issued by US standard setters and international standard setters (as part of International Financial Reporting Standards). If Canadian GAAP had continued to exist as its own set of standards, there would likely be convergence towards one of these sets of standards which means that a difference may not have existed.

175.1.4 Please identify the columns in Exhibit A2-2 that present the amounts reported for regulatory accounting under US GAAP and the amounts that would have been reported for regulatory accounting under Canadian GAAP.

Response:

The column that presents the amounts reported for regulatory accounting under US GAAP are on pages 36 and 38 titled "Corporate US GAAP (external)". The column that presents the amounts that would have been reported under pre-changeover Canadian GAAP is on pages 36 and 38 titled "Corporate Canadian GAAP".

175.2 What are the estimated annual costs associated with preparing the annual reconciliation required by Order G-117-11?

Response:

Since the 2012 reconciliation was primarily prepared by salaried management and exempt staff, who do not attract overtime costs, there were negligible incremental O&M costs incurred the first time that this specific reconciliation was prepared. However, on a prospective basis, it would be expected that there would be incremental annual costs in preparing the annual reconciliation required by Order G-117-11.

As indicated in Section D3.3.1 of the 2014-2018 PBR Application, specific accounting records in compliance with pre-changeover Canadian GAAP are no longer maintained since they are not used for any other reporting purpose. The conceptual challenges associated with preparing a reconciliation of amounts reported for regulatory accounting to those amounts that would otherwise be reported under Canadian GAAP are also discussed in the response to BCUC IR 1.175.1.3.

Therefore, for 2013 and beyond, there could be incremental costs expected to be incurred that are associated with maintaining another set of accounting records to recreate pre-changeover Canadian GAAP from 2011 onwards, overtime paid to unionized staff that assist with preparing the reconciliation in the timelines given that overlap year-end external financial statement reporting, and incremental actuarial services to compile and re-create pension and OPEB balances that would have been reported under pre-changeover Canadian GAAP which are no longer tracked or maintained.

Since FortisBC requested cessation of this reconciliation beginning for 2013, FortisBC's 2014 to 2018 PBR Application did not take into account any increases in actuarial costs required to perform accounting valuations under pre-changeover Canadian GAAP, any potential increased O&M or any additional accounting system capital expenditures to complete the reconciliation on a prospective basis.

175.3 Please discuss if FBC considers it appropriate to include a sustainable cost saving from 2013 Projection to 2013 Base should the requirement to provide the reconciliation between amounts reported for regulatory accounting under US GAAP versus Canadian GAAP be eliminated? If yes, please provide the amount.

Response:

No, when considering the response to BCUC IR 1.175.2, there should be no cost savings adjustment between 2013 Projection and 2013 Base upon the removal of the requirement to prepare this reconciliation. The 2013 Base forecast contemplates the removal of this USGAAP to pre-changeover Canadian GAAP reconciliation, so in the absence of this happening, the increased O&M and capital expenditures described in the response to BCUC IR 1.175.2 would have to be included the 2014-2018 forecasts.

176.0 Reference: Exhibit B-1, p. 249

Depreciation Rates

"FBC proposes to provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR."

176.1 Please explain how any changes in the depreciation rate may impact customer rates during the PBR period? Is FBC proposing to flow through any changes to depreciation rates in the year subsequent to when the study is filed?

Response:

As indicated in Section B 6.8 on page 72 of the Application, depreciation expense will be re-forecast at each Annual Review. The depreciation expense will be forecast using the approved depreciation rates at the time. As indicated in Section D3.3 on page 249 of the Application, FBC proposes to provide an updated depreciation study during the term of the PBR Period and anticipates that, subject to Commission approval, any updated depreciation rates would be implemented during the term of the PBR. Depending on the timing of when the depreciation rates are approved, FBC believes it is likely they would be effective in the year subsequent to when the study is filed.

176.1.1 Will the depreciation study be included in the Annual Review or is it expected to be a separate proceeding?

Response:

FBC anticipates that an updated depreciation study would be filed as part of the Annual Review process during the term of this PBR.

177.0 Reference: Exhibit B-1, p. 220; Appendix F1, Shared Services Agreement

FBC states that "Effective January 1, 2014, the sharing of costs between FBC and FEI will be incurred under the Amended and Restated Mutual Shared Services Agreement included as Appendix F1."

177.1 Please explain why an "amended and restated" shared services agreement is necessary. What has changed in regards to the relationship of shared services between FEI and FBC?

Response:

FEI and FBC desired to make two minor changes to the current Mutual Shared Services Agreement and decided to record these two revisions via an Amended and Restated Mutual Shared Services Agreement. The Amended and Restated Mutual Shared Services Agreement includes revised protection of privacy language and clarifies the mechanism for the sharing of third party contractor costs to reduce duplication of efforts between FEI and FBC.

177.2 Please explain why the Shared Service Agreement is only valid for one year (from January 1, 2014 to December 31, 2014) according to page 6 of Appendix F1? What is the purpose of the automatic 1 year renewal clause outlined in section 6.1 of the Agreement?

Response:

The Amended and Restated Mutual Shared Services Agreement has a term of January 1 – December 31 to correspond with the fiscal year of both FBC and FEI. It has a one year term in order to allow both parties to revisit the terms and conditions of the agreement on a yearly basis, if so required. The purpose of the automatic one year renewal clause is to automatically renew the agreement for an additional one year term without requiring the re-execution of any documents if FBC and FEI are satisfied with the current terms and conditions.

Section 3.1 of the Agreement outlines the compensation for services and shared costs:

> The party receiving Services agrees to reimburse the party providing Services for all reasonable expenses it has incurred in providing such Services, including, without limitation, such portion of the annual salary and benefits of relevant employees as is determined by the party providing Services to be allocable to the party receiving Services based on the nature and extent of Services actually provided during the applicable period and for Services provided by a third party contractor, such portion of the amount invoiced by the third party contractor as is determined by the party contracting for the Services to be allocable to the party receiving a portion of the Services based on the nature and extent of Services actually received in the applicable period.

177.3 Please explain who the "third party contractor" would be, as referenced in the clause above.

Response:

A third party contractor would be any party retained by either FEI and/or FBC to provide services to FEI and/or FBC, as applicable, who is not an employee of FEI or FBC.

177.4 Please discuss whether the reference to "annual salary and benefits of relevant employees" is meant to convey a market allocation rate based on arms length transaction?

Response:

The use of annual salary and benefits is meant to convey the market costs for the relevant employees. However, the allocated costs are calculated in accordance with the 2012 – 2013 RRA Decision, whereby the salary and benefits exclude a charge for overheads and a profit margin therefore it would be incorrect to represent that these transactions as true arms- length transactions.

178.0 Reference: Exhibit B-1, p. 251-255; Appendix F3, p. 27

Capitalized Overhead

FBC states "The 2013 Overheads Capitalized Study reviewed two methodologies for estimating a reasonable overheads capitalized rate…The Survey based Model suggests a 15 percent rate while the Mathematical Model yielded a 17 percent rate." (Exhibit B-1, p. 252)

In Appendix F3, the KPMG Report states that "The assessment of the two models provides a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards. However, KPMG finds the Survey Model provides a 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." (Appendix F3, p. 27)

FBC states that the "Company is requesting that the current capitalization rate of 20 percent be approved by the Commission and remain at that same rate over the PBR term." (Exhibit B-1, p. 255)

178.1 Although, the current 20 percent capitalized overhead rate falls within the wide range of approved rates in other Canadian utilities, please explain why FBC does not use any of the figures produced by the two methodologies?

Response:

The Company does not think it would be appropriate to change its overhead capitalization rate for the following reasons:

1. The Survey and Mathematical Methodologies are subjective in nature and therefore the rates determined are estimates. In their Executive summary, KPMG states that the Survey Methodology rate "is estimated to be approximately 15 percent", suggesting that the rate is indicative in nature, but not definitive;
2. As illustrated in Exhibit B-1, Section D.3.7, page 255, Table D3-2 the Company expects capital spending from 2014 – 2018 on average to be greater than in the 2010 – 2013 period and to lower the overhead capitalization rate would be counter to the trend;
3. A one percent change in the Capitalized Overhead rate will result in an approximate 0.25 percent change in Customer rates. If the Capitalized Overhead rate were to be reduced to 17 percent or 15 percent, Customer rates would increase by approximately 0.75 or 1.25 percent respectively; and

4. The current capitalization rate of 20 percent is well within the range compared to the 19 utilities surveyed in the KPMG Overhead Capitalization Methodology Review Appendix F3.

178.2 Given that KPMG believes that the more appropriate capitalization rate is approximately 15 percent, please explain why this was not proposed by FBC?

Response:

Please refer to the response to BCUC IR 1.178.1.

178.3 Would it reasonable to apply a simply mathematical average to the rates produced by the two methodologies? Why or why not?

Response:

As noted in the 2013 Overheads Capitalized Study KPMG made the following observations (Appendix F3, Page 39) “Among the utilities surveyed both in United States and Canada there is no single or common methodology for allocating indirect costs to capital”, but to suggest that an average of the two estimates would be a more reasonable estimate is arbitrary and would be no better an estimate than the current rate or the rates produced by the two methodologies.

Please also refer to the response to BCUC IR 1.178.1.

178.4 Has FBC considered if it should seek approval for a phased in reduction to Capitalized Overhead rates during the PBR period to minimize rate variations? (Perhaps a reduction of 1 percent/year)

Response:

The Company is not proposing to reduce the Capitalized Overhead rate. However, if the Commission ordered the Company to reduce the Capitalized Overhead rate, the Company would recommend a phased in approach to the rate reduction in order to mitigate the impact on customer rates.

Please also refer to the response to BCUC IR 1.178.1.

In the last revenue requirement decision, the Commission stated that while capital expenditures may be reduced in any test period, the amounts being charged to capital through the capitalized overhead allocation continue to rise in both dollars and as a percentage (if loadings are also included in the equation). The Commission specifically stated on page 74 of that decision that "there may be a need to more closely align the capitalized overhead rate to the changing capital expenditures rather than to simply rely upon a percentage of operating costs as is currently the case."

178.5 Please clarify whether this concern is addressed in this Application.

Response:

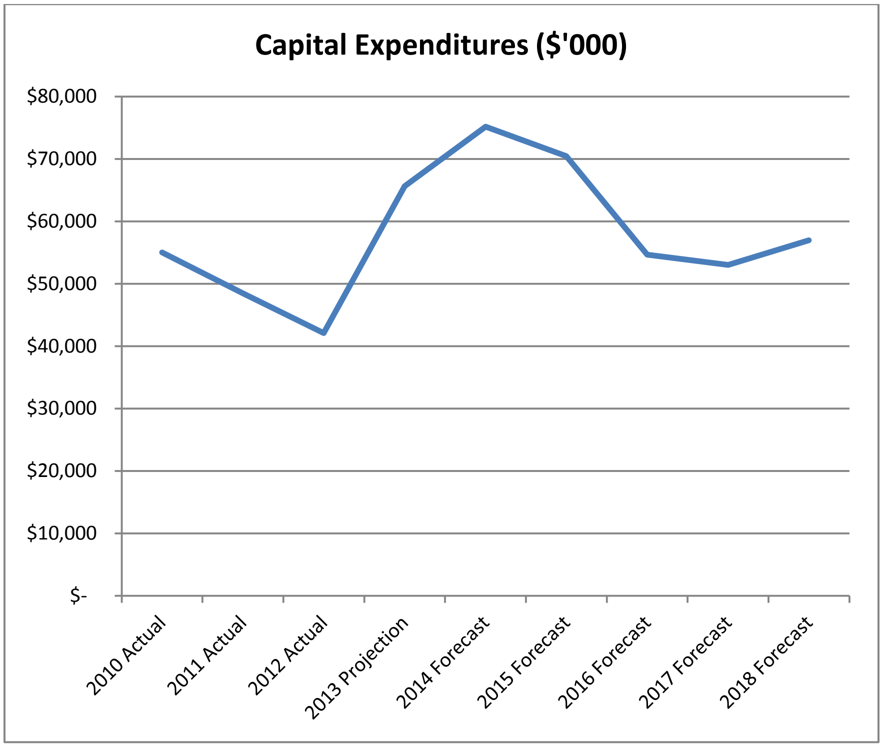
The Company considered the Commission's statement in evaluating the capitalized overhead methodology and concluded that the current approach was still appropriate for the following reasons:

(a) Employing a fixed percentage of O&M is the normal industry standard;

(b) Varying the capitalized overhead with the level of capital expenditures would introduce greater variability in rates, and

(c) As illustrated in Exhibit B-1, Section D.3.7, page 255, Table D3-2 the Company expects capital spending from 2014 – 2018 on average to be greater than in the 2010 – 2013 period and to lower the overhead capitalization rate would be counter to the trend.

The following graph utilizes FBC's capital expenditure data from Table D3-2 filed in the Application to graphically illustrates its capital expenditures from 2010 and through to the end of the PBR term. While the graph shows fluctuating levels of capital expenditures during the period, FBC's actually and proposed capitalized overhead rate remains at 20 percent.



178.6 Please provide the total dollars charged to capitalized overhead in the corresponding years in the above graph.

Response:

The total dollars actually charged to capitalized overhead for the years 2010 to 2013 and forecast for 2014 – 2018 are as follows:

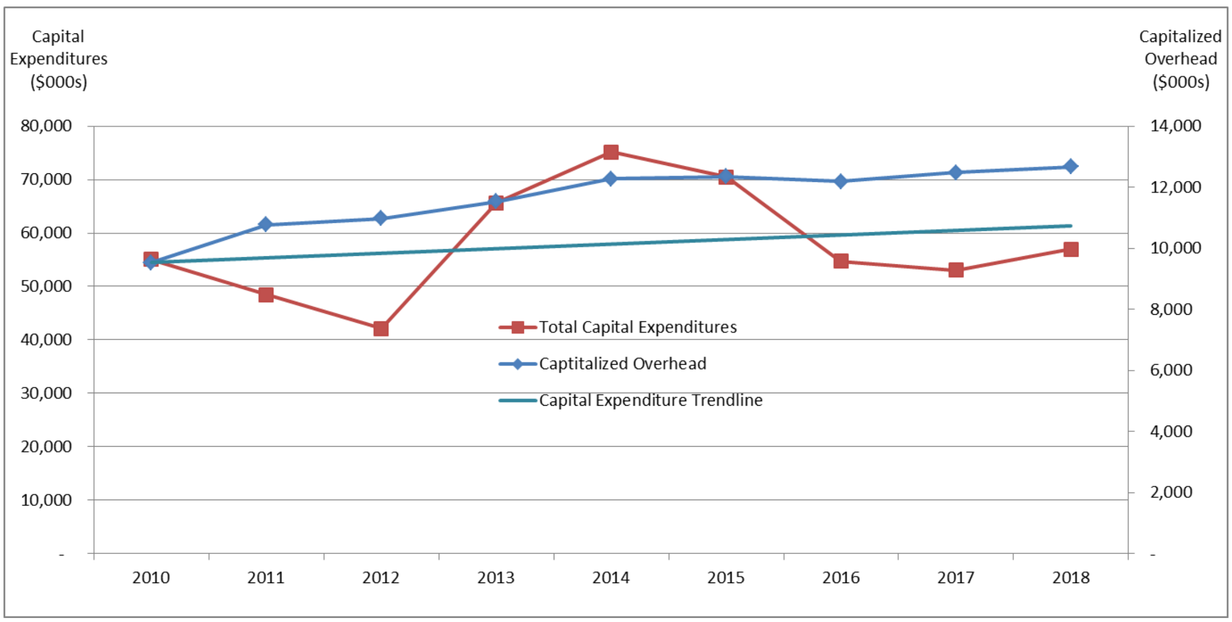
	Actual				Forecast				
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Capitalized Overhead	9,529	10,777	10,969	11,524	12,277	12,349	12,192	12,476	12,660

The forecast capitalized overhead amounts for 2014 through 2018 are equal to 20 percent of the O&M as calculated under the PBR Plan as shown in Table B6-5 on page 53, Exhibit B-1 of the Application.

178.7 While the graph shows fluctuating levels of capital expenditures during the period, FBC's actual and proposed capitalized overhead rate remains at 20 percent. Please discuss whether FBC has considered any other allocation method in the determination of a capitalized overhead rate. Could a percentage of forecast capital expenditure be used as an allocator of O&M support costs to capital projects? Why or why not?

Response:

Since capital expenditures can be variable in nature, it is useful to compare trends. The graph below illustrates that capitalized overhead and the capital expenditure trend-line exhibit a similar rate of increase over the 2010 – 2018 period even though capital expenditures varied from year to year.



It 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. Maintaining a level overheads capitalized rate would reduce the variability.

Please also refer to the response to BCUC IR 1.178.5.

179.0 Reference: Exhibit B-1, p. 255-257; Appendix F3

Direct Overhead

"The purpose of the direct overhead loading is to allocate costs that relate to T&D capital projects specifically rather than having those costs included in the corporate capitalized overhead and allocated to Generation or other non-T&D capital projects." (Exhibit, B-1, p. 255)

KPMG confirmed that there is no duplication of costs capitalized by the direct overhead and capitalized overhead methodologies (Exhibit B-1, p. 256)

179.1 Isn't the terminology "Direct Overhead" an oxymoron? Can a particular expense be both a direct costs and an overhead cost at the same time?

Response:

The term Direct Overhead is used in order to recognize the methodology by which certain direct costs are allocated to T&D capital projects. The costs are directly attributable to T&D capital projects and could be directly charged to T&D capital projects, but for administrative efficiency are direct charged into a holding account, then allocated to T&D capital using a Direct Overhead loading factor in a manner similar to how Capitalized Overhead is applied.

179.2 Is FBC aware whether BC Hydro utilizes a "Direct Overhead" loading on their Transmission and Distribution capital projects?

Response:

The Company is not aware whether BC Hydro utilizes a ""Direct Overhead" loading on its Transmission and Distribution capital projects.

179.3 Is FBC aware of any other comparable utility that utilizes a direct overhead allocation methodology for T&D projects?

Response:

FBC is not aware of any other comparable utility that utilizes a direct overhead allocation methodology for T&D projects. The Company also submits that the direct overhead costs could be directly charged to all of the individual capital projects, however to ease the administrative burden and provide for additional efficiency, it has directly charged these costs to a holding account, then loaded the costs from the holding account to the individual capital projects. In addition to describing this methodology in the current Revenue Requirement Application, it has described this methodology in its 2000, 2004, 2005, 2006 and 2012/13 Revenue Requirements Applications and has been charging these costs to capital consistently for the past 13 years.

During the last revenue requirement proceeding, FBC indicated that "In 2008-2010, the Okanagan Transmission Reinforcement (OTR) project has a specific Capitalized Overhead percentage applied to it in recognition that the project was an Engineer/Procure/Construction Manage (ECPM) project that should not attract the full Capitalized Overhead rate or Direct Overheads. This in turn has an impact on the overhead loading percentage of the remaining projects[20]."

179.4 Is the concept of FBC's Direct Overhead loading for T&D projects similar to the OTR project, in that, these T&D projects would attract an overhead amount that is higher than would for other capital projects of the Company? Please discuss.

Response:

No. The Direct Overhead loading for T&D capital projects is a loading methodology that allocates T&D costs that could be directly charged to the T&D capital but to take advantage of administrative efficiencies, the costs are charged to a holding account then allocated from that account using a Direct Overhead rate. The Direct Overhead rate is calculated by dividing the direct overhead amount for the year by T&D capital expenditures in the year. The amount of direct overhead that would be charged to the T&D capital expenditures in the year would be the same regardless of whether the costs were directly charged to T&D capital or the costs were charged to a holding account and then allocated from that account using a Direct Overhead rate.

[20] 2012-2013 RRA Application, Exhibit B-8, BCUC IR 2.51.2

I. DEFERRAL ACCOUNTS

180.0 Reference: Exhibit B-1, p. 246-249

Deferral Account Financing

In its Application, FBC provides three recent Commission decisions which have approved a carrying cost based on AFUDC (Orders G-163-12, G-66-13, and G-56-13).

180.1 Is FBC also aware of these three Thermal Energy projects which have been allowed only a Weighted Average Cost of Debt (WACD) as its carrying cost?

- Telus Garden CPCN Application, Order C-1-13 dated February 4, 2013 - The Commission states on page 38 of that decision it "finds the reasoning behind the FortisBC (2012-2013 RRA and ISP) Decision is appropriate and applicable to any deferral accounts that are approved in the subsequent TGTES rate application. **FAES is directed to calculate the carrying cost on deferral accounts using the weighted average cost of debt**[21]."
- Kelowna District Energy System CPCN Application, Order C-8-13 date July 23, 2013. The Commission states on page 71 of the decision "The Panel echoes the finding in previous Commission decisions that deferral accounts are regulatory assets, not true capital assets. The purpose of the RDDA is to enable FAES to offer competitive rates initially and facilitate adoption of this technology through deferring a portion of the cost of service. The use of the KDESVA is to capture certain uncontrollable costs. The Panel views both of these deferral accounts to be tools for rate smoothing purposes. Accordingly, the Panel directs **FAES to calculate the carrying costs on these two deferral accounts by using the weighted average cost of debt based on the deemed short-term and long-term debt components of the capital structure**[22],…"
- Pacific Northern Gas (West Division) 2013 RRA Decision, Order G-114-13, dated August 1, 2013, the Commission outlined the principles used in the treatment of deferral accounts, which includes: "(c) For deferral accounts for non-capital items which are amortized beyond one year, the

[21] In the Matter of an Application by Fortis Alternative Energy Services Inc. for a CPCN for the Telus Garden Thermal Energy System and for Approval of the Rate Design and Rates Decision, February, 4, 2013.

[22] In the Matter of an Application by Fortis Alternative Energy Services Inc. for a CPCN for the Kelowna district Energy system and Rate Design and Rates Application, July 26, 2013.

> appropriate return is the utility's Weighted Average Cost of Debt (WACD)[23]."

Response:

FBC had been aware of the decisions in these two Thermal Energy projects, but was not aware of the decision in Order G-114-13 regarding Pacific Northern Gas (West Division). However, it has now read through that decision for background and provides the following comments.

In the decision accompanying Order G-114-13, FBC notes this is the first time that the Commission has stated that it considers it has established "key principles" behind the treatment of deferral accounts. From pages 44 and 45 of that decision:

> *In the FortisBC Inc. 2012-2013 RRA Decision (FortisBC Decision), the Commission established key principles for the treatment of deferral accounts. Excerpts from the FortisBC Decision which outlined the principles were provided as part of BCUC IR 1.52 (Exhibit B-3). These principles with application to this proceeding are summarized as follows:*
>
> *(a) When determining the length of an amortization period for a deferral account, the key factors to consider are the benefits of rate smoothing, the length of time where there is direct value related to the item being amortized, and the increased costs that longer amortization periods impose on ratepayers due to the accumulation of financing charges.*
>
> *(b) Deferral accounts are regulatory assets, not true capital assets; therefore, it is more appropriate for deferral accounts for non-capital items to earn an interest rate of return, not a rate base rate of return.*
>
> *(c) For deferral accounts for non-capital items which are amortized beyond one year, the appropriate return is the utility's Weighted Average Cost of Debt (WACD). For deferral accounts for non-capital items which are amortized over a period of one year or less, the appropriate return is the utility's short term interest cost.*
>
> *(d) For deferral accounts related to capital, the appropriate return is the utility's Weighted Average Cost of Capital (WACC) [Order G-110-12, pp. 104-106].*

And later in the decision (on page 48), *"the Panel accepts that it is appropriate for non-capital expenses deferred for periods of greater than 5 years be granted a full WACC return."*

[23] In the Matter of an Application by Pacific Northern Gas (West Division) for Approval of its 2013 Revenue Requirements Application Decision, August 1, 2013.

FBC agrees that it is helpful to have key principles established around the use of deferral accounts, and agrees with principle (a) as articulated above regarding the length of amortization period for a deferral account, noting that the issue around "the increased costs that longer amortization periods impose on ratepayers due to the accumulation of financing charges" is mitigated by the value to ratepayers of not paying for these items until a later period, and therefore should not be a major consideration.

In the case of the FortisBC Decision where these concepts were first introduced, there was no explanation laid out in the FortisBC Decision itself as to what had changed that justified a departure from long-held regulatory principles, and FBC (and FEI, FEVI and FAES) have stated on the record in various proceedings that they do not agree with the conclusions reached by the Panel.

FBC's disagreement with the principles around the financing of deferrals has been described fully in Section D3.2 of its Application. In addition, FBC provides a further example of the issues that can arise with applying a principle based on what the nature of expenditures would be in the absence of a deferral account. Consider a situation where GAAP has changed, such that an item that was previously capitalized is now required to be expensed, and as a result the utility requests a deferral account to continue with the same treatment for ratepayers as had previously existed. Under the principles articulated by the Commission, this deferral would have been afforded a WACC return as part of capital, but due to a change in GAAP (and no change in the fundamental nature of the item or its regulatory treatment), would now be afforded only an interest or a WACD return.

Regarding Order G-114-13 specifically, FBC respectfully notes that the Commission has applied its principles in an inconsistent manner. For example, in its decision (on page 40):

> *"Therefore, the Panel denies the $887,000 capital additions for the Rio Tinto Alcan modernization project for 2013. The Panel directs PNG to place the costs incurred for the RTA project in the test year 2013 into a non-rate base,* ***non-interest bearing deferral account****. PNG is directed to apply for approval of the capital costs associated with the RTA project as part of its 2014 RRA."* **[emphasis added]**

These amounts are clearly of a capital nature and therefore, using the Commission's own principles, should attract a WACC return, but have been denied any return at all.

FBC considers that, regardless of whether the Commission characterizes these assets as "capital" or "regulatory", a utility will not be able to capitalize them with 100% debt so the net effect is to reduce the actual equity ratio below that approved (assuming the utility can effectively use a portion of the equity which was deemed to capitalize rate base and instead use it to capitalize those interest bearing deferrals without risking its financial wellbeing). The net effect to reduce the ROE below the level at which it has been approved. FBC does not believe this to be appropriate.

Regarding the two FAES decisions noted above, FBC again points out the problems that arise when making a distinction in deferral items between capital and non capital items. The RDDA and the KDESVA accounts are ones that hold items of both a capital and a non capital nature (as many deferral accounts do). Drawing a distinction between whether an item, in the absence of a deferral account, would have been of a capital or operating nature, is illogical when the recording of that amount in a deferral account removes its original classification and treats all expenditures in the same manner.

180.2 Does FBC see any major differences between those decisions that have approved carrying costs of AFUDC and those decisions that have approved WACD?

Response:

No FBC is not able to differentiate why a WACC vs. a WACD treatment was approved for items that have the same or similar characteristics. Please see Section D3.2 and the response to BCUC IR 1.180.1 for examples of deferral accounts with same or similar characteristics that have received approval for different financing treatments.

FBC further states that "the moment an item is placed into a deferral account for future recovery or refund; it ceases to become an 'operating cost' or 'current period charge.' It has now become akin to a capital item in that costs are being incurred in one period and not being recovered from ratepayers until a future period." (Exhibit B-1, p. 248)

180.3 Is FBC aware of any other regulator adopting this capital versus operating distinction in the determination of the nature of deferral accounts?

Response:

FBC does not make a distinction between capital and operating items, as they are the same once placed into a deferral account. It is the Commission that has attempted to differentiate deferral items in this manner. FBC is not aware of other regulators that have made this distinction.

180.4 Has FBC considered the short term and long term nature of each deferral account as justification for the allowance for using short term interest versus long term financing using debt and equity.

Response:

No. Given that all these items are financed for regulatory purposes in a similar fashion (in the same way that working capital and capital expenditures are financed the same way for regulatory purposes), there is no reasoned basis on which to draw a distinction in this manner.

180.5 The above preamble appears to suggest a form of revenue decoupling mechanism, whereby the revenues are 'decoupled' from their costs. Is FBC able to discuss these decoupling mechanisms in other jurisdictions and their allowed carrying costs?

Response:

FBC does not agree that the preamble suggests a form of revenue decoupling. Revenue decoupling, in the common usage of that term, does not refer to revenues being decoupled from costs; rather it refers to revenues being decoupled from sales volumes. A revenue decoupling mechanism is one approach that can be taken, for example, to overcome (or help to overcome) the disincentive that a utility has to pursue demand-side management (DSM) programs, because DSM programs will tend to cause reduced throughput and profitability. If a revenue decoupling mechanism has been put in place then the utility will not experience the same profitability decline from DSM-induced throughput decreases.

181.0 Reference: Exhibit B-1, pp. 258 – 276

Deferral Account Financing

181.1 For each deferral account with an amortization period of one year or less, please discuss why in FBC's opinion financing costs in excess of the short-term borrowing rate are appropriate, given the short-term nature of the deferral.

Response:

Please refer to the response to BCUC IR 1.180.4.

181.2 For each deferral account with an amortization period of five years or less, please discuss why in FBC's opinion financing costs in excess of FBC's weighted average cost of debt are appropriate.

Response:

Please refer to the response to BCUC IR 1.180.4.

181.3 For each deferral account with an amortization period of three years or greater, please discuss why, in FBC's opinion, this amortization period is considered appropriate. Please discuss the amortization period, taking into consideration the following:

- The benefits of rate smoothing.
- The length of time where there is a direct value related to the item being amortized.
- The increased costs those longer amortization periods impose on the ratepayer.

Response:

As discussed in the Application at Section D3.2, the return on deferral accounts that is afforded the utility is to compensate for the time period that the deferral is being financed by the utility. This is the case whatever the nature or time period of recovery for the account.

The following deferral accounts discussed in Section D4 have amortization periods of three years or greater.

4.3.1 Rate Stabilization Deferral Mechanism (4 years): This account is established solely for the purpose of reducing rate variability over the period 2014-2018. A deferred credit will be recognized in 2014 and amortized over the following 4 years. FBC was directed by the Commission in Order E-15-12 to develop a rate smoothing proposal. In addition, the RSDM has the effect of reducing the cumulative 2014-2018 rate impact because it reduces rate base in the early years.

4.3.5 Interest Expense Variance (3 years): Please refer to the response to BCUC IR 1.190.6

4.3.7 Property Tax Variance (3 years): Please refer to the response to BCUC IR 1.191.4

4.4.1 Demand Side Management (15 years): Please refer to the response to BCUC IR 1.232.2

4.4.2 On-Bill Financing Pilot Program (15 years): Please refer to the response to BCUC IR 1.193.1

4.4.3 2014-2018 PBR Application (5 years): Please refer to the response to BCUC 1.194.2

4.4.4 Pension & OPEB Expense Variance (EARSL): Please refer to the response to BCCUC IR 1.214.11

4.5.2 On-Bill Financing Participant Loans (10 years): Please refer to the response to BCUC 1.193.1.1

4.5.9 Deferred Debt Issue Costs (term of debentures): The amortization of the deferred debt issue costs (costs to issue long-term debt and obtain proceeds) are equivalent to the term of the related debt instrument issued. FBC's long-term debt is issued for longer terms in order to match up the expected useful life of its assets (several terms of 30 years or greater). Regardless of whether an entity is rate-regulated or not, debt issue costs are in theory deferred or capitalized and amortized over the term of the related debt and this treatment is supported by various accounting guidance.

Some of the deferral accounts listed above, such as interest expense variance, property tax expense variance, and Pension/OPEB expense variance, hold debit balances in some years and credit balances in other years. In these cases, the "increased costs" become "increased benefits".

182.0 Reference: Exhibit B-1, pp. 258-259, Table D4-1

Deferral Accounts

Table D4-1 provides details of deferral Accounts providing benefits to customers and the Utility.

182.1 Regarding "Preliminary and Investigative Charges": Would the elimination of this deferral account lead to lower future rate base costs and provide more effective cost control by FBC? Why, or why not?

Response:

Elimination of this deferral account would not provide more effective cost control by FBC. The extent of the engineering activities that is required to determine the feasibility of projects for utility services, which is the scope of work captured in this deferral account, is not affected by the accounting treatment. As the costs that are captured in this account are transferred to the capital projects upon commencement, the preliminary work forms part of the overall project cost and is therefore subject to the same focus on cost control as all of FBC's capital expenditures.

Preliminary and investigative charges for projects subject to CPCN applications are excluded from rate base until the project enters Plant in Service (prior to BCUC approval these costs are held in deferral accounts outside of rate based and transferred to Construction Work in Progress (CWIP) Subject to AFUDC, which is also excluded from rate base, upon approval).

Preliminary and investigative charges for regular capital projects are included in rate base deferrals. Rate base treatment is appropriate because the costs relate directly to capital projects and should be similarly financed. The alternative treatments would be to record the costs directly into projects in CWIP, which is administratively more burdensome, or to increase Base O&M as required to expense the costs as incurred. FBC believes the former treatment is appropriate given the capital nature of the expenditures. In addition the need for preliminary engineering costs may vary from year to year. Given the relatively small magnitude of FBC's O&M it may not be possible to absorb all of these costs without jeopardizing other O&M activities.

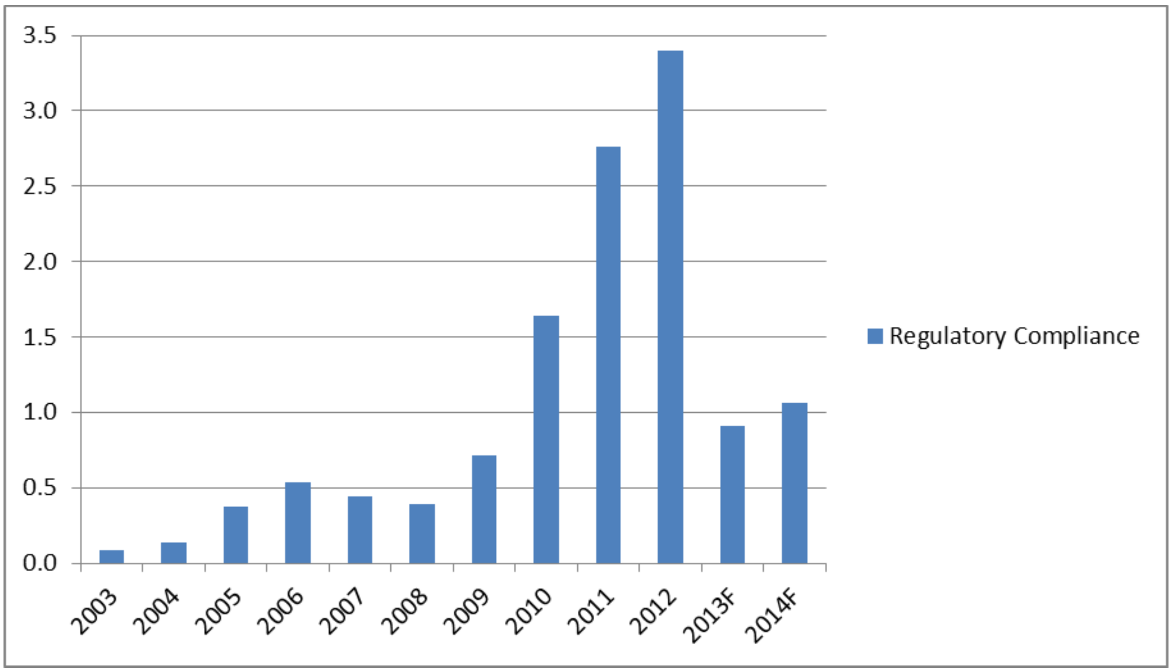
182.2 Regarding "Cost of Regulatory Compliance," Figure D4-1 shows that the cost of regulatory compliance has increased to $18,600,000 in 2014 Forecast. Please explain why. Please provide a table of these costs over the past 10 years.

Response:

It is the cost of Energy Policy (DSM) accounts that is $18.6 million, not the cost of Regulatory Compliance. The cost of Regulatory Compliance in 2013 is $0.9 million and rises to $1.1 million in 2014.

The following figure sets out the mid-year deferred cost of regulatory compliance over the past 10 years.

Mid-Year Balances of Regulatory Compliance Deferral Accounts (2003-2012)



182.3 Regarding "Cost of Regulatory Compliance," Figure D4-1 shows that the cost of regulatory compliance has increased to $18,600,000 in 2014 Forecast. Would non deferral of these costs lead to better cost control by the Utility? Why?

Response:

The regulatory compliance cost is not $18.6 million as explained in the response to BCUC IR 1.182.3.

Non-deferral of these costs would not lead to better cost control. The Company endeavours to ensure that all costs and revenues are prudently incurred, regardless of whether they are included as operating expenses, capital expenditures or deferral accounts. Costs that are deferred are still subject to review and approval as part of the revenue requirements application processes. The deferral treatment of the incremental costs of regulatory compliance is necessary because the timing, number and complexity of regulatory proceedings in any year is variable. Deferral of the costs for later recovery ensures that only the actual costs of regulatory proceedings are taken into rates, and in the case of large and costly proceedings (such as the 2009 COSA and Rate Design Application and the 2012-2013 RRA and ISP) reduces rate variability.

183.0 Reference: Exhibit B-1, p. 239-240, p. 264

Property Tax Deferral Account

"FBC seeks approval for deferral treatment of property taxes as they are driven primarily by legislation, market values of properties and/or political programs outside the control of the Company." (Exhibit B-1, p. 238)

During the last revenue requirement, FBC was approved a Property Tax Asset deferral account to capture the variance "related to the BC Assessment Authority's review of asset valuation, in the event that a review is conducted, as it is largely out of the Company's control and any impact cannot be reasonably forecast at this time[24]." During the review process, FBC confirmed that it "is not requesting that all variances between forecast and actual 2012 and 2013 property taxes be captured in the Property Tax Variance Deferral Account, only those variances that specifically result from the potential BC Assessment Authority review of the valuation of certain electrical system assets and rates[25]."

183.1 Please explain why FBC did not previously apply for approval to include all property tax related variances in this deferral account? What items related to property taxes have changed since that last RRA and why does FBC consider that all matters related to property taxes are factors outside the control of the Company.

Response:

Previously FBC has been granted regulatory mechanisms for dealing with unexpected property tax variances. Since the inception of its PBR Plans beginning in 1996, material changes in property taxes would be eligible for consideration under the terms of the PBR which recognized the need to address uncontrollable expenses resulting from legislative or regulatory acts of governments. In its 2012–2013 Revenue Requirements Application FBC was granted deferral account treatment for changes arising out of an expected valuation review by the BC Assessment Authority. Therefore, FBC's request for deferral of property tax variances in the Application is consistent with the treatment of property tax variances that has been previously granted.

FBC has experienced consistent increases in property tax payments based on increased capital investments in taxable improvements such as distribution lines, transmission lines, substations and generation, as well as increasing pressures on government finances. Due to this increasing assessment base, FortisBC believes it is appropriate to seek deferral treatment of property

[24] 2012-2013 RRA Application, Exhibit B-1, p. 108

[25] 2012-2013 RRA Application, Exhibit B-4, BCUC IR 1.72.1

taxes. This is consistent with the treatment of property taxes accorded the other FortisBC utilities.

Further, FBC would like to clarify that elements affecting property tax payments are primarily driven by factors outside the control of the Company. Property taxes are a function of:

1. Property Assessments: Property valuation methodologies are set out in legislation. While property assessments can be appealed, most of FortisBC's properties are valued on a cost basis using either legislated rates for distribution lines and transmission lines, or legislated manuals for substations and generating facilties, based on self-reported quantities. In these cases FortisBC is limited to compliance by ensuring inventories are correct and reasonable. FortisBC reviews all assessment notices annually.

2. Property Tax Rates: Property tax rates are set by municipalities, the Province (Surveyor of Taxes) and other taxation authorities. Tax rates cannot be appealed. FortisBC does verify each tax notice annually to ensure tax rates are set within legislated parameters.

3. Municipal Boundaries: changes to municipal boundaries generally results in higher taxes to a facility because municipal rates are typically higher than those found in rural areas.

FBC states that "the Company can face uncontrollable changes in tax laws or accepted assessing practices in respect of Federal income tax, Provincial income tax, Provincial sales taxes or any other tax that may be imposed, all of which are out of the Company's control." As such, FBC is requesting to establish a Tax Variance deferral account to "capture and accumulate variances from forecast, as referenced in Section D4.3.7, resulting from the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies at Federal, Provincial, Municipal or any other level of jurisdiction."(p. 241)

183.2 Please clarify the reference above to section D4.3.7. Is this the section that is included on page 264 of the Application, titled "Property Tax Variance?"

Response:

The preamble to BCUC IR 1.183.2 from page 241 of the Application does not apply to property tax. The variances referred to in the preamble are captured in the Tax Variance account described in Section D4.3.6. The Property Tax Variance is captured separately as described in Section D4.3.7

183.2.1 Please explain how this deferral account differs from the proposed "Property Tax Variance Deferral Account" discussed on page 240 of the Application.

Response:

The Tax Variance deferral account referred to in the preamble is described in Section D4.3.6, and the Property Tax Variance deferral account is described in Section D4.3.7, both found at page 264 of the Application.

183.3 Is this account meant to capture the differences in "Income Taxes" and changes to incomes tax laws over the PBR term?

Response:

The Request for Tax Variance Deferral Account (Section D.2.4.1) on page 241 of the Application, which is the same as the Tax Variance deferral account in Section D4.3.6 on page 264, is meant to capture the uncontrollable aspects of income taxes and sales taxes including changes in income tax laws, tax rate changes and audit reassessments. This Tax Variance account is different than the Request for Property Tax Deferral Account on page 240 (Section D2.2.3.)

184.0 Reference: Exhibit B-1, p. 260

Preliminary and Investigative Charges

"Preliminary and Investigative Charges are either charged to capital or expensed and are not tax-effected."

184.1 Please discuss why Preliminary and Investigative Charges deferrals are not tax-effected similar to other FBC deferral accounts.

Response:

Preliminary and Investigative Charges are not tax effected similar to other deferral accounts as these are capital costs at the preliminary and/ or investigative stage. Other deferred charges that are eligible for tax deduction in the period incurred are tax effected so that customers receive the tax deduction over the same period as the amortization of the deferred charge. Similarly, Preliminary and Investigative Charges, once approved, are transferred to capital and once put into service whereby customers receive the tax deduction over the tax life of the asset. This treatment is consistent with Order G-52-05 which includes the Commission Panel's decision to explicitly exclude preliminary and investigative costs from using net-of-tax deferral accounting.

185.0 Reference: Exhibit B-1, p. 261

Rate Stabilization Deferral Mechanism (RSDM)

"The RSDM would take the form a deferred credit to be recognized in rate base during 2014 and amortized over the PBR Period to reduce rate variability over the five years of 2014 – 2018. Based on FBC's current forecasts of revenue requirements over the PBR Period, an initial credit of $22.6 million would yield annual rate increases of 3.3 percent, exclusive of the items listed in Section A1" (Exhibit B1, p. 261)

185.1 Please provide the detailed calculation to support the initial balance of $30 million before tax and $22.6 million net of tax. How was this figure derived or is this simply a plug to yield a 3.3 percent annual increase over the five year PBR period? If the latter, please discuss why the precise rate of 3.3 percent is deemed just and reasonable? If not, explain how it was derived.

Response:

The RSDM is premised on the following requirements:

1. The RSDM account in 2014 and its subsequent amortization during 2015-2018 should be such as to generate a uniform rate impact in all years.
2. The RSDM in 2014 and its subsequent amortization should be such that it balances to zero by 2018.

The RSDM amount in 2014, and the amortization profile that satisfies these conditions is shown in the following calculation.

Please also refer to the Table below:

Rate Stabilization Parameters	2014	2015	2016	2017	2018	Total
Rate Stabilization Component (Pre Tax)	30,089	-	-	-	-	**30,089**
Tax Component	(7,522)	-	-	-	-	**(7,522)**
Amortization of Rate Stabilization Component (Pre Tax)	-	(3,240)	(13,483)	(9,466)	(3,900)	**(30,089)**
Tax Component	-	810	3,371	2,367	975	**7,522**
Net Rate Stabilization Component (Post Tax)	**22,567**	**(2,430)**	**(10,112)**	**(7,100)**	**(2,925)**	**-**

185.2 Please clarify whether the "initial credit of $22.6 million" should be "the initial debit of $22.6 million?"

Response:

In 2014, the $22.6 million is a debit to cost of service, (as shown on Exhibit B-1, Page 277 Section E: Financial Schedules, Line 29) and consequently there is a $22.6 million credit to 2014 Rate Stabilization Deferred Mechanism – RSDM deferred charges (as shown on Exhibit B-1, Page 287, Table 1-B, Section E: Financial Schedules Line 5 RSDM).

185.3 Given the proposed flow through items, items tracked outside of O&M formula, other deferrals and amortizations of certain deferral balances, how does FBC actually administer this 3.3 percent annual increase?

Response:

The RSDM does not result in an annual 3.3 percent increase, as indicated in the quotation above (unless the excluded items in aggregate net to zero rate impact). The effect of the RSDM is to eliminate significant rate variances arising from factors that are known at the time of filing the Application and to satisfy the terms of Commission Order E-15-12 issued in May 2012. The RSDM in the amount of $22.6 million will be recognized in 2014 and the account will be drawn down over the 2015-2018 period as set out at page 261 of the Application (Table D4-2).

The drawing down of the initial balance in the deferral account provides a rate smoothing effect without affecting other cost accounts over the 2015-2018 period. The rate-setting process which incorporates formula-driven and annual forecasts is unchanged with or without the RSDM. The only cost account that changes is the amortization of Deferred Charges.

185.3.1 Will the annual rate increase be fixed at 3.3 percent and then all the flow through and deferral items are transferred and captured in the RSDM? Or will the 3.3 percent annual increase be the minimum increase, then be adjusted by all other flow through and deferral items? Please provide an illustrative example.

Response:

The mechanism for setting rates in accordance with the RSDM is explained in the response to BCUC IR 1.185.3. All other flow-through and deferral items will be captured in the appropriate and respective accounts, not in the RSDM, ensuring transparency of accounting for all cost accounts. As noted, unless the sum of all other changes (from the forecast in the Application) nets to zero, annual increases over the 2015-2018 period will not be 3.3 percent. However it is not correct to state that 3.3 percent will be the minimum increase. Depending on the net impact of the items excluded from the RSDM, rate increases may be higher or lower than 3.3 percent.

185.3.2 If other deferral accounts like PPE result in rate variability during the PBR period will the RSDM amortization be adjusted to smooth the overall rate increases? Why?

Response:

FBC is not proposing to adjust the RSDM balance or the annual amortization of the RSDM from the Application. The purpose of the proposed RSDM is not to provide a perfectly even rate profile but rather to mitigate a specific set of circumstances which would otherwise see a 6 percent rate reduction in 2014 followed by an approximately 15 percent increase in 2015. FBC's expectation is that the actual rate increases over the 2015-2018 period will fluctuate to a much smaller degree, and will not require additional measures to reduce year to year changes.

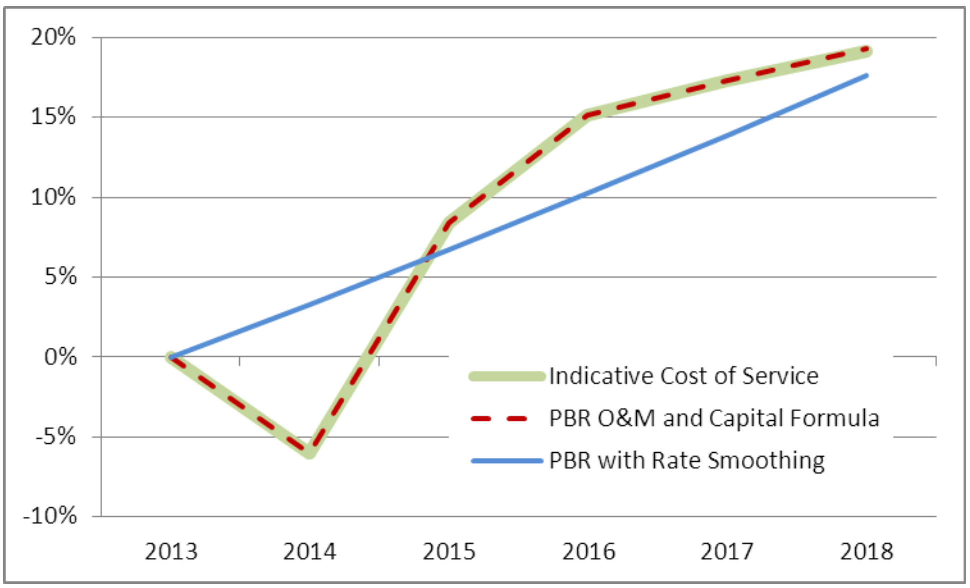
The Utility proposes the RSDM to "mitigate the variability in revenue requirements during the PBR period."

185.4 Is FBC concerned that this rate smoothing will distort the actual costs of service to customers and lead to inappropriate price signals? Why, or why not?

Response:

No. In FBC's view the rate profile resulting from the stabilization mechanism provides a more appropriate price signal than would otherwise be the case. The relative profiles are shown in Figure B7-1 at page 75 of the Application and reproduced below. For example, in the absence of rate stabilization, the reduced 2014 "price signal" could lead customers to make choices that would be inconsistent with future prices, particularly if the short term price was being used to make longer-term investment decisions.

Figure B7-1: Comparison of Rate Increase Scenarios



186.0 Reference: Exhibit B-1, p. 262

BC Hydro Application for New PPA with FortisBC Inc.

"As a party to the PPA, [FortisBC] will actively participate in the regulatory process, including responding to [IRs], and will incur costs, the amount of which will depend on the scope and type of process determined by the Commission."

Commission Order G-117-13 established a written proceeding for the review of the BC Hydro application for approval of rates between BC Hydro and FBC with regards to Rate Schedule 3808, Tariff Supplement No. 3 – Power Purchase and Associated Agreements, and Tariff Supplement No. 2 to Rate Schedule 3817.

186.1 The FBC PBR Application includes 2013 additions to this deferral account of $175,000 before tax. Please discuss if this amount was derived assuming an oral hearing, written hearing, NSP or SRP.

<u>Response:</u>

The forecast provided for the possibility of an oral process to review the application.

186.1.1 Considering that a written proceeding has been established, please provide a breakdown of the most up to date costs incurred to date and the forecast costs associated with FBC's participation in the proceeding, using the following categories: legal, regulatory, consulting and other costs.

<u>Response:</u>

Current and forecast costs for this proceeding are as follows:

($000s)	Current	Forecast
Legal Fees	15	49
Staff Expense and Other	1	1
Total	16	50

186.2 Please explain why FBC did not forecast these regulatory costs in the 2012-2013 RRA and ISP Application.

Response:

FBC did forecast that it would incur costs for the PPA renewal in the 2012-13 RRA. The regulatory process costs were included with the costs of negotiating the PPA contract. In this Application, FBC separates the cost of negotiating the PPA from the costs of the regulatory approval process for greater transparency with regard to its classifications of deferral accounts in Section D4.

187.0 Reference: Exhibit B-1, pp. 52-53

Insurance Expense Deferral

"FBC is also requesting flow-through treatment and exclusion from the PBR formula for insurance expense, which is also uncontrollable in nature, and consistent with the treatment previously accorded to FEI and proposed in the current FEI application." (Exhibit B-1, p. 52)

"…the O&M allowed under PBR will be recalculated yearly in the PBR Annual Review, based on updated forecasts of customers, composite inflation rates, and those items tracked outside of the formula, for the upcoming year." (Exhibit B-1, p. 53)

187.1 For each of 2011, 2012 and 2013, please provide the forecast and actual (or projected, in the case of 2013) insurance expense, excluding the City of Kelowna.

Response:

Insurance expense includes insurance premiums, asset valuations and first and third-party liability costs, however the Insurance Expense Variance Deferral Account referred to in D4.3.4 on page 263 of Section D4 of the 2014-2018 PBR Application is meant to only capture variances between forecast and actual insurance premiums. The charts below show Insurance premiums only and full insurance expense for the years requested.

Insurance Premiums

	Approved	Actual
2011	$1,211,000	$1,216,582
2012	$1,272,000	$1,275,616
2013	$1,335,000	$1,400,000 (Projected)

Insurance Expense

	Approved	Actual
2011	$1,393,000	$1,398,582
2012	$1,441,000	$1,946,359
2013	$1,449,000	$1,566,000 (Projected)

187.1.1 Please provide the reasons for any significant variances provided in the previous question.

Response:

For 2011, no explanation has been provided as the variance of approximately $6 thousand is not significant.

For 2012, the actual insurance expense is approximately $500 thousand higher than the 2012 approved insurance expense primarily due to a large unexpected insurance deductible as well as higher than expected first and third party claims, all of which are outside the Company's control. This insurance expense does not include a one-time refund of self-insurance reserve as approved in the 2012-2013 RRA decision to customers of $447 thousand. Please refer to the response to BCUC IR 143.2 for treatment including this repayment.

The variance between 2013 approved and projection is explained in the response to BCUC IR 1.143.6.

187.1.2 Please provide the 2013 forecast insurance expense for the City of Kelowna.

Response:

The estimated insurance expense forecast for the City of Kelowna for 2013 is $22 thousand.

187.2 In preparing the FBC 2012-2013 RRA and ISP Application, please discuss the process that was undertaken by FBC to forecast insurance expense.

Response:

Insurance Expense is made up of two major categories, Insurance Premiums and first and third-party claims. With respect to Insurance Premiums, FortisBC reviews renewal premium trends from past years and also consults with Aon Reed Stenhouse Inc. our insurance broker to provide feedback on Insurance market premium forecasts for the upcoming year. Also considered when forecasting Insurance Premiums is the potential for growth at FortisBC.

First and third-party claims are the second major category considered when forecasting insurance expense. FortisBC will look at claim trends for the Company over the past few years. Consideration is also given to potential growth from acquisition (i.e. Kelowna) and capital projects where the increase in exposure may impact the number of claims arising.

The FBC 2012-2013 RRA application contemplated deferral treatment for Insurance Expense including both insurance premiums and first and third party claims. For the 2014-2018 PBR Application, FBC is requesting Insurance Expense Variance deferral account as stated on page 263 in Section D4, item 4.3.4 to capture the difference between actual and forecast costs of insurance premiums only.

187.3 Please discuss the degree of 'controllability' that FBC has over forecasting insurance expense for a period of one year.

Response:

To clarify, insurance expense is comprised of insurance premiums, asset valuations and first and third party liability costs, however the Insurance Expense Variance Deferral Account referred to in D4.3.4 on page 263 of Section D4 of the 2014-18 PBR Application is meant to only capture variances between forecast and actual insurance premiums which are uncontrollable in nature. Insurance 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. Tightening of capacity for power business is currently causing insurers to be much more selective and disciplined; and this applies further pressure on pricing. 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.

187.4 How often and when do FBC's insurance premium renewals take place?

Response:

Insurance premium renewals take place annually on July 1 of each year.

187.5 Please discuss FBC's involvement in negotiations during insurance premium renewals.

Response:

FBC insurance is part of the Fortis Inc. Group of Companies and participates in the Corporate insurance program. The Insurance groups at Fortis Inc. and FBC work together to place the insurance program on a yearly basis. The Fortis Insurance group works with its broker Aon Reed Stenhouse Inc. (Aon) each year to provide professional insurance services to the Fortis Group of Companies and FBC. As part of the process, each year FBC and Aon assess the insurance market to determine the best course of action to provide FortisBC the appropriate coverage at the most competitive rates. This is accomplished by continual contact with underwriters capable of insuring the Fortis Group of Companies risk profile. Annually, FBC and Aon provide insurers with updated underwriting information (Statement of Values, Loss Control reports etc.) for renewal purposes. FBC and Aon also attend in person meetings with the majority of the markets, in particular, the lead markets on the FBC program to present the FBC risk and answer any questions insurers may have concerning FBC. The Fortis Insurance group also meets annually with peer organizations and Aon to benchmark the FBC insurance program.

188.0 Reference: Exhibit B-1, p. 263

Insurance expense variance

FBC states that "Insurers are becoming more sensitive to catastrophic risks such as earthquake, hurricane and forest fire losses and, therefore, companies exposed to these types of losses will have continued scrutiny on premiums."

188.1 Has FBC considered partial self insurance to minimize this impact?

Response:

FBC considers self insurance and its retention/deductible levels annually at renewal. This topic is also discussed with our insurance broker (Aon Reed Stenhouse) to assess the cost/benefit of moving to partial self insurance and/or higher retention/deductible levels.

189.0 Reference: Exhibit B-1, pp. 232-237, 263-264

Interest Expense Variance

FBC indicates that changes in debt issuances and interest rates after 2014 will be reflected in the Company's annual rate setting process during the PBR period. (Exhibit B-1, p. 233-234)

189.1 Please discuss the intended use of the proposed interest expense deferral account. Does FBC intend to flow through the balances in this account to customers during any subsequent year during the PBR term?

Response:

The intended use of this proposed interest expense deferral account is to ensure that customers pay the actual cost of interest expense related to interest rates and long-term debt balances, due to their uncontrollable nature. FortisBC intends to amortize the annual variances, either positive or negative, that arise during each of the years of the 2014-18 PBR term, over a three year period into customer rates. For example, the deferral balance that arises in 2014, would be amortized into customer rates for 2015 to 2017. The deferral balance that arises in 2015, would be amortized into customer rates for 2016 to 2018.

189.2 In order to mitigate rate impact to customers, should there be a cap for this deferral account? If so, how should the cap be determined?

Response:

No, this deferral account should not be capped as it is not being established for purposes of rate mitigation, but rather for ensuring that customers only pay the actual interest expense on interest rates and long-term debt balances as they are not controllable by the Company.

For clarification, the variance is not known in advance of setting rates; the balance is nil, therefore the establishment of this deferral does not mitigate rate impact. Once a year has passed and a variance balance is established, only then could the impact be mitigated to customers by lengthening the amortization period.

Additionally, the variances accumulated in this deferral account could either be costs to be recovered from customers in the future or savings to be passed along to customers in future rates, therefore the suggestion that rate mitigation is required is premature. For instance, FortisBC had a similar interest expense deferral account approved during its 2007-2011 PBR Agreement which saw in excess of $6 million flowed back to customers which was used to reduce future customer rates.

FBC proposes to also capture "variances associated with the volume and timing of issuing long-term debt, as compared to what has been forecast for rate-setting purposes. The <u>ability and timing</u> to issue long-term debt is also dependent on the debt markets and <u>are not within FBC's control</u>." (Exhibit B-1, p. 237) (Emphasis added)

189.3 Please explain why the "ability and timing" of issuing debt is not within the Company's control? Is this comment related to FBC's credit ratings and credit worthiness in capital and debt markets or is this meant to convey that FBC is too small to influence fluctuations in those markets?

Response:

While the Company may wish to issue debt at a specified time, term and coupon, all of these variables are affected by the supply and demand dynamics of public debt markets, and therefore, beyond the control of FBC.

Due to system reliability and growth initiatives to serve customers, the Company does not have the ability to choose the timing of capital expenditure programs. The Company funds its capital in part with debt and therefore, is required to issue debt to the capital markets. The Company has limited amount of short-term available credit, and so it must obtain long-term debt financing. When such financing is required, the Company may face adverse market conditions, which may affect the cost, amount and term of its debt issuance. Attempting to "wait out the market" is not prudent, as there is no certainty as to when the market conditions may be more favourable, and the Company would need to carry greater short-term debt that would hamper its liquidity and may stall its capital expenditure program. Further, the pricing and demand in the debt markets can change quickly, but the Company's capital program takes several months to execute on. It would not be fiscally responsible for the Company to try and time the execution of its capital program to match favourable market conditions.

While the comment in the preamble is not specifically referring to FBC's credit ratings or credit worthiness, should there be an instance where they potentially deteriorate, such as an adverse decision in the GCOC Stage 2 Proceeding, lower credit ratings could restrict the Company's ability and timing to issue debt compared to companies with higher credit ratings, during times of adverse market conditions. While the preamble was unrelated to the size of FBC, the Company would agree with the IR that the Company is not of a size to influence fluctuations in capital and debt markets.

189.4 FBC has filed evidence as an "affected utility" in the Commission's Generic Cost of Capital Proceeding (GCOC), including two credit agency's report which discusses FBC's credit position. Does FBC normally meet with these credit agencies to discuss impacts to their business and credit position?

Response:

Yes, FBC communicates with the credit agencies on a regular basis to discuss impacts to the business and its credit position.

189.5 Please explain FBC's position on how and when the determinations from the current GCOC Stage 2 proceeding will impact FBC during the PBR period? If the new ROE and equity ratio are determined effective January 1, 2013 how will those changes be flowed through to customers?

Response:

FBC's Application contemplated that its 2014 rates would be set prior to completion of the Stage 2 GCOC proceeding and a flow-through of any impact arising from the Stage 2 GCOC following a decision in that proceeding.

Commission Order G-151-13 maintains existing 2013 rates as interim and approved an interim rate increase of 3.3 percent, effective January 1, 2014.

Based on the Amended Regulatory Timetable set out in Order G-151-13, a Stage 2 GCOC decision is now expected to precede a decision on this Application. FBC therefore proposes that any impact on 2013 interim rates be recorded in the existing GCOC Revenue Requirements Impact deferred account for amortization into rates in 2014. Changes to the 2014-2018 Revenue Requirements, if any, arising from the Stage 2 GCOC decision will also be incorporated into the 2014-2018 calculations.

In the last revenue requirement proceeding, FBC has also proposed an Interest Expense Deferral Account and had considered it to be "somewhat controllable." This deferral account was denied by the Commission on the basis that FBC should make its best efforts to forecast and manage this account as part of its day to day business operations[26].

189.6 Given the Commission's previous position on this requested deferral account, please explain what circumstances have changed in FBC since the last revenue requirement application that the Commission should consider at this time.

Response:

FortisBC's lack of controllability over interest rates and macro-economic conditions has not changed since the 2012-13 RRA Decision and the Company believes that re-instating an interest expense deferral account similar to what was in place during FortisBC's 2007-2011 PBR Agreement ensures that only the actual cost of debt is borne by customers. FortisBC does not agree with the rationale of the Commission's previous decision which stated that the Company make "its best efforts to forecast and manage this account as part of its day to day

[26] 2012-2013 RRA Decision, August 15, 2012, p. 117

business". FortisBC has issued public debt several times since 2004 and has never had the ability to make "best efforts" to manage the Government of Canada bond yield and credit spread, both which are influenced by the prevailing economic environment. Economic conditions could lead to supply and demand imbalances in the market which could positively or negatively affect the demand and tenors of debt issues, including those sought by FortisBC. These market and macro factors are clearly beyond FortisBC's "best efforts to forecast and manage this account as part of its day to day business" as suggested in the 2012-13 RRA Decision.

For example, the 2014 forecast interest expense has been estimated, as shown in Table D1-3 on page 236, Section D1 of the 2014-18 PBR Application, assuming a 2013 $105 million debt issuance with a forecast coupon rate of 4.25% and a 2014 $100 million debt issuance with a forecast coupon rate of 4.75%. This interest rate was based on third party financial institutions and agencies' publications. The latest indicatives at the end of August 2013 for the 2013 debt issuance suggest a coupon rate closer to 4.70% which is significantly higher than the 4.25% used to forecast 2013 and 2014 interest expense at the time of filing the PBR Application. The increase in this coupon rate has been driven in part by decisions made by foreign investors not reinvesting in Canadian bonds and the market's expected resurgence in the US economy, none of which the Company could make "its best efforts to forecast and manage this account as part of its day to day business". As part of an Evidentiary Update filing, FortisBC will provide an update to its interest expense forecast for 2013 and 2014 which would flow the variance in interest expense back to customers, no different than what would be accomplished with a deferral account.

190.0 Reference: Exhibit B-1, pp. 232, 236, 263-264

Interest Expense Variance

With respect to financing costs, FBC submits that "Debt financing costs include the interest expense on issued debt, interest expense on forecast new issuances and financing fees. Debt consists of Long-term and Short-term Debt." (p. 232)

"This proposed…deferral account would capture the impact on interest expense of short-term and long-term interest rate variances, as well as variances associated with the volume and timing of issuing long-term debt, as compared to what has been forecast for rate-setting purposes." (p. 263)

Table D1-3 presents an overview of the 2014 Forecast weighted average debt rate.

190.1 Please discuss the degree of 'controllability' that FBC has over forecasting interest rates for a period of one year.

Response:

Debt capital markets are dynamic and volatile, changing constantly to reflect current and expected economic conditions and government monetary and fiscal policy. While FBC takes appropriate measures to develop a forecast of interest rates, it has no control over actual interest rates, therefore, little control over the forecasting risk that is associated with interest rates. While in theory the risk over one year forecasts should be less than five years, capital markets are dynamic so variability in forecasts is always present. Please refer to the response to BCUC IR 1.189.6.

190.2 Please identify the debt components in Table D1-3 that have fixed interest rates and those that have variable interest rates.

Response:

The additions to the requested Interest Expense Variance Deferral account are not necessarily the result of whether the debt components have fixed or variable interest rates, however the requested identification of the debt components in Table D1-3 of the 2014-18 PBR Application are as follows:

Table D1-3: Overview for Forecast Interest Expense ($ thousands) to provide response to BCUC IR 1.190.2

Description of Debt	Maturity Dates	Coupon Rates	2013 Approved Weighted Average Balance ($000s)	2013 Approved Interest Expense ($000s)	2013 Projection Weighted Average Balance ($000s)	2013 Projection Interest Expense ($000s)	2014 Forecast Weighted Average Balance ($000s)	2014 Forecast Interest Expense ($000s)	Reference
Long-Term Debt									
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200	25,000	2,200	(A)
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193	25,000	2,193	(A)
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953	25,000	1,953	(A)
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672	134,055	7,346	(A)
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600	100,000	5,600	(A)
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195	105,000	6,195	(A)
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405	105,000	6,405	(A)
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000	100,000	5,000	(A)
MTN Series 2013	30 year est.	4.25%	65,425	3,108	30,781	1,308	105,000	4,463	(B)
MTN Series 2014	30 year est.	4.75%	-	-	-	-	12,603	599	(B)
Total Long-Term Debt			690,425	40,325	655,781	38,525	736,658	41,952	
Short-term Debt			31,777	1,106	32,218	773	(1,465)	(38)	©
Short-term Debt rate			3.48%		2.40%		2.60%		
Financing Fees				946		550		671	(D)
Total Long-Term and Short-Term Debt			**722,202**	**42,377**	**687,999**	**39,848**	**735,193**	**42,585**	
Weighted Average Debt Rate				**5.87%**		**5.79%**		**5.79%**	

Notes:

A. Long-term debt which has already issued (Series G, H, I, 1-04, 1-05, 1-07, MTN Series 1-2009 and MTN Series 2-2010) have fixed interest rates and the interest expense will not change throughout the term of the 2014-2018 PBR, unless there was early repurchase of the debt instruments, which is unlikely.

B. MTN Series 2013 and MTN Series 2014 debt instruments will have fixed interest rates when issued. However the real variability and effect on interest expense, exists between the 4.25% coupon rate forecasted for the 2013 debt issuance and the 4.75% coupon rate forecasted for the 2014 debt issuance, both included in the 2014-2018 PBR Application, and the actual interest rates achieved at the point in time of issuance. For example, the latest indicatives at the beginning of September 2013 for the 2013 debt issuance suggest a coupon rate closer to 4.70% which is significantly higher than the 4.25% used to forecast 2013 and 2014 interest expense at the time of filing the PBR Application. Just because FortisBC has provided a forecasted interest rate for a debt instrument that will be issued with a fixed interest rate does not mean that the rate itself is known at the time of setting revenue requirements. The ability to capture the difference between forecasted and actual interest rates is the critical point of the requested Interest Expense Variance Deferral account, rather than if the debt instrument itself has a fixed or variable interest rate.

C. Short-term debt will be exposed to variable interest rates. FortisBC has requested that the variances between actual and forecasted short-term interest rates, but not the average debt balance, be included in the requested Interest Expense Variance Deferral account.

D. Many of the financing fees are more fixed in nature and not directly affected by fixed or variable interest rates, with the exception of operating credit facility standby fees. Standby fees, also known as utilization fees, will be based on a fixed rate determined once the credit facilities agreement is renewed and amended in April or May of 2014. The Standby fees for each of 2013 and 2014 have been forecast at approximately $0.2 million per year based on the standby fee rate of 20 basis points from the Second Amended and Restated Credit Agreement executed on April 17, 2013. The bank syndicate will change the standby fee rates based on general market and economic conditions. Only the variances in the forecast and actual standby fee rate on operating credit facility fees would be included in the requested Interest Expense Variance Deferral account.

To summarize, the request for an interest expense variance deferral account is not based on whether the interest rate is variable or not, but rather the variability that occurs between the rate forecast used to set revenue requirements at a point in time and the actual rate obtained, as well as the long-term debt weighted average debt balances.

190.2.1 For those debt components that have a variable interest rate, please discuss the forecasting methodology and the sources used to forecast interest rates.

Response:

In the response to BCUC IR 1.190.2, the short-term debt draws on the operating credit facilities were identified as being subject to variable interest rates and the forecasting methodology was described on pages 234-235 in Section D1 of the 2014-2018 PBR Application as follows:

1.1.2.2 Forecast of Short-Term Interest Rates

FBC's short-term borrowing rate is based on the rate at which it issues Bankers' Acceptances (or the Canadian Dealer Offered Rate or CDOR) plus an Acceptance Fee Rate, and on the Prime Lending Rate. Since CDOR is not forecast by economists, a forecast needs to be derived by FBC; therefore, the Company must first obtain the 3-Month T-Bill rate forecast then convert it to a CDOR forecast. FBC does this by taking the 3 year historical spread between CDOR and the 3-month T-Bill rate which is calculated as 0.27 percent from 2010 to 2012. At the time of filing this RRA, the 3-month T-Bill rate is projected to increase from approximately 1.2 percent in 2014 to approximately 3.5 percent by 2018. The Company then layers on the Acceptance Fee Rate which is 1.0 percent based on the pricing arising from the Company's April 2013 renewal of its operating credit facility agreement. The Prime Lending Rate (estimated at the Overnight Bank Rate plus 200 basis points) is projected to increase from 3.20 percent in 2014 to 5.50 percent by 2018. Based on the pricing arising from the April 2013 extension of the operating credit facility agreement, there is no prime rate margin associated with Prime Rate Margin borrowings. The short-term interest rate forecasts using current information are shown in Table D1-2 below. The forecasts for 2015 through 2018 will be updated as part of the Company's annual rate setting process during the PBR period.

The sources to forecast treasury Bill and benchmark Government of Canada Bond interest rates used in determining overall interest rates for short-term debt and are based on projection made by Canadian Chartered banks (Toronto Dominion, Royal Bank of Canada, Bank of Nova Scotia, CIBC, National Bank Financial and Bank of Montreal) which are included in Appendix E1: Forecast Assumptions of the 2014-18 PBR Application

While the 2013 and 2014 debt instruments will have fixed interest rates once they are actually issued, the real variability, and effect on interest expense, exists between the actual interest rates achieved upon issuance of each respective debt instrument and the 4.25% coupon rate forecasted for the 2013 debt issuance and the 4.75% coupon rate forecasted for the 2014 debt issuance. These forecasted coupon rates were derived from the same Canadian Chartered Bank publications included in Appendix E Appendix E1: Forecast Assumptions of the 2014-18 PBR Application

190.3 Does FBC propose to forecast interest expense for a period of one year during the PBR period and update the forecast as part of the Annual Reviews? If not, please explain otherwise.

Response:

Yes.

190.4 Please provide the approved and actual (projected, in the case of 2013) weighted average debt rate for 2011, 2012 and 2013.

Response:

Please refer to the response to BCUC IR 1.190.4.1

190.4.1 For each of 2011, 2012 and 2013, please provide the impact of the variance between the approved and actual weighted average debt rate on the cost of debt included in revenue requirements, taking into consideration the deemed debt component of the capital structure.

Response:

	2011	2012	2013
Approved Weighted average rate on Total Debt	6.18%	6.02%	5.87%
Approved Deemed Debt Component	60%	60%	60%
Approved Mid-Year Rate Base	1,093,241	1,112,302	1,203,669
Approved Interest Expense	40,505	40,182	42,377
Actual Weighted average rate on Total Debt*	6.15%	5.92%	5.79%
Approved Deemed Debt Component	60%	60%	60%
Approved Mid-Year Rate Base	1,093,241	1,112,302	1,203,669
Interest Expense	40,353	39,533	41,815
Variance	(152)	(649)	(562)

*2011 and 2012 are representative of actual debt rate, while 2013 is based on projected debt rate.

190.5 Does FBC intend to apply the variance between the approved and actual weighted average debt rate to the deemed debt component of the capital structure for the same year in order to calculate additions to the Interest Expense Variance account? If not, please discuss how FBC intends on calculating additions to the deferral account.

Response:

No, the additions to the Interest Expense Variance Deferral account are not intended to be driven by the overall weighted average debt rate using the deemed debt component of the capital structure. To clarify, the weighted average debt rate will not drive the variances to be captured in the deferral account. Rather, FortisBC intends to add to the Interest Expense Variance Deferral account all variances between forecast and actual overall interest expense, with the exception of:

- Variances between forecast and actual interest expense variances driven by the differences on forecast and actual average short-term debt balances, and
- Variances between forecast and actual financing fees, but not the variance in financing fees resulting from changes between the forecast and actual standby fee rate discussed in the response to BCUC IR 1.190.2, which would be included in the Interest Expense Variance Deferral account.

190.5.1 Please provide an example calculation to support FBC's proposed methodology for calculating additions to the Interest Expense deferral account, using the variance between the 2013 approved and projected weighted average debt rate in Table D1-3. Please provide an explanation to support the calculation.

Response:

As discussed in the response to BCUC IR 1.190.5, FBC is not proposing to use the overall weighted average debt rate to determine additions to the requested Interest Expense Variance deferral account. The following two tables and discussion explain how FBC is proposing to include additions to the Interest Expense Variance deferral account. Table 1 provides the comparison of 2013 projected and approved interest expense and includes references of (a) to (c which are then used to demonstrate, in Table 2, how the variances on rates and volume are either deferred or not.

Table 1 – 2013 approved interest expense against the 2013 projected interest expense

Description of Debt	Maturity Dates	Coupon Rates	2013 Approved Weighted Average Balance ($000s)	2013 Approved Interest Expense ($000s)	2013 Projection Weighted Average Balance ($000s)	2013 Projection Interest Expense ($000s)	Interest Variance	
Long-Term Debt								
Series G	28-Aug-23	8.80%	25,000	2,200	25,000	2,200		
Series H	01-Feb-16	8.77%	25,000	2,193	25,000	2,193		
Series I	01-Dec-21	7.81%	25,000	1,953	25,000	1,953		
Series 1 - 04	28-Nov-14	5.48%	140,000	7,672	140,000	7,672		
Series 1 - 05	09-Nov-35	5.60%	100,000	5,600	100,000	5,600		
Series 1 - 07	04-Jul-47	5.90%	105,000	6,195	105,000	6,195		
MTN Series 1 - 2009	02-Jun-39	6.10%	105,000	6,405	105,000	6,405		
MTN Series 2 - 2010	24-Nov-50	5.00%	100,000	5,000	100,000	5,000		
MTN Series 2013	30 year est.	*4.25%	65,425	3,108	30,781	1,308		
MTN Series 2014	30 year est.	4.75%	-	-	-	-		
MTN Series 2016	30 year est.	5.50%	-	-	-	-		
Total Long-Term Debt			690,425	40,325	655,781	38,525	1,800	(a)
Short-term Debt			31,777	1,106	32,218	773	333	(b)
Short-term Debt rate**			3.48%		2.40%			
Financing Fees				946		550	396	(c)
Total Long-Term and Short-Term Debt			**722,202**	**42,377**	**687,999**	**39,848**	2,528	
Weighted Average Debt Rate				**5.87%**		**5.79%**		

The following Table 2 demonstrates how the variance of $2,528 on total interest expense identified in Table 1 is accounted for, either as an addition to the Interest Expense Variance Deferral account or not.

Table 2 – Deferral of Interest Expense Variances

	Ref		Interest Variance to be deferred	Interest Variance not deferred	Total Interest Variance
				($000s)	
Long-term Debt variance on rate and volume					
Approved Long-term Debt rate and volume		40,325			
Projected Long-term Debt rate and volume		38,525			
Total Long-term Debt variance on rate and volume	(a)	**1,800**	1,800		1,800
Short-term Debt variance on rate and volume					
Approved Short-term Debt volume		31,777			
Approved Short-term Debt rate		3.48%			
Projected Short-term Debt rate		2.40%			
Rate differential		1.08%			
Short-term Debt variance on rate differential		343	343		343
Approved Short-term Debt Interest Expense		1,106			
Projected Short-term Debt interest expense		773			
Total Short-term Debt variance		333			
Less: variance on rate differential		(343)			
Short term variance on volume		(11)		(11)	(11)
Total Short-term Debt variance on rate and volume	(b)	**333**	343	(11)	333
Financing Fees variance					
Estimated Unused Short-term Debt		118,223			
Approved Standby Fee Rate		0.30%			
Projected Standby Fee Rate		0.20%			
Rate differential		0.10%			
Standby Fee variance on rate differential		118	118		118
Approved Financing Fees		946			
Projected Financing Fees		550			
Financing Fees variance		396			
Less: variance on standby fee rate differential		(118)			
Financing Fees variance		278		278	278
Ttoal Financing Fees variance	(c)	**396**	118	278	396
			2,261	267	**2,528**

Notes:

a) All interest expense variances (the entire $1,800 thousand) related to Long-term debt interest rates and long-term debt average balances are to be deferred.

b) Short-term interest expense variances driven by differences between approved forecast short-term interest rates of 3.48% and projected short-term interest rates of 2.40%, resulting in a variance of $343 thousand, are to be deferred, while the short-term interest expense variance driven by differences between forecast and projected average short-term debt balances ($11 thousand) are not deferred.

c) Short-term interest expense variances driven by differences between forecast standby rate of 30 basis points and the actual standby fee rate of 20 basis points, resulting in a variance of $118 thousand, are to be deferred, while the remaining financing fee costs of $278 thousand are not deferred.

In this example calculation, of the total $2,528 thousand variance between 2013 Projected and Approved Interest Expense, $2,261 thousand would be added to the Interest Expense Variance Deferral account while the remaining $267 thousand would not be deferred.

190.6 Please explain why FBC considers a three year amortization period to be appropriate for the proposed Interest Expense Variance deferral account.

Response:

A three year amortization term for the Interest Expense Variance deferral account is appropriate as it provides a reasonable balance between a long enough period to smooth the customer impact for any potential large variances that may arise in a given year, with a short enough period for which customers are still paying for the true cost of service in a timely manner. In addition, the amortization period is consistent with the Commission's approval of the three-year amortization term for FEI's Interest Variance deferral account.

191.0 Reference: Exhibit B-1, p. 264

Tax Variance

191.1 Please discuss the degree of 'controllability' that FBC has over forecasting income taxes rates for a period of one year.

Response:

While FortisBC can provide forecasted income tax rates at a point in time based on government publications and sources, FortisBC has absolutely no "controllability" over whether the governments change the income tax rates or laws subsequent to submitting revenue requirements forecasts to the Commission for approval for the applicable test year.. Governments have previously made changes to tax laws and income tax rates which have led to variances from income taxes approved for rate-setting purposes including the change in the general corporate tax rate by 1% effective July 1, 2008, changes in the capital cost allowances ("CCA") related to new transmission and distribution acquired after February 22, 2005, and changes to computer hardware and system software CCA classes acquired after January 27, 2009 and before February 2011 from Class 50 to Class 52. All these changes were uncontrollable and the Company was approved to include these effects in a deferral account during its 2007-2011 PBR Agreement. FortisBC is requesting a similar deferral account for its 2014-18 PBR term as it is reasonable to assume that there will be further income tax rate and law changes made by governments over the course of the 2014-2018 PBR term.

191.2 Please provide examples of factors that lead to variances in income taxes over the past several years, including any uncontrollable changes in tax laws or accepted assessing practices.

Response:

Please refer to the response to BCUC IR 1.191.1.

191.3 How were income taxes treated during FBC's last PBR period? Please discuss.

Response:

Pursuant to Commission Order G-58-06, the "Z" Factor Provision under FortisBC's 2007-2011 PBR Agreement allowed for the recovery or refund of costs that arose from changes in Acts of legislation or regulation of government, which included changes in the Income Tax Act, tax regulations and income tax rates. All such changes were beyond FortisBC's control during the last PBR period and the Company is seeking the Tax Variance Deferral Account for the term of the 2014-18 PBR period to capture these same changes in Acts of legislation or regulation of government, as well as potential audit reassessments and compliance costs to adhere to such changes.

191.4 Please explain why FBC considers a three year amortization period appropriate for the Property Tax Variance deferral account.

Response:

A three year amortization term for the Property Tax Variance deferral account is appropriate as it provides a reasonable balance between a long enough period to smooth the customer impact for any potential large variances that may arise in a given year, with a short enough period for which customers are still paying for the true cost of service in a timely manner. In addition, the amortization period is consistent with the Commission's approval of the three-year amortization term for FEI's Property Tax Variance deferral account.

191.5 Please discuss the degree of 'controllability' that FBC has over forecasting income taxes rates for a period of one year.

Response:

Please refer to the response to BCUC IR 1.191.1 which is the same question as above.

192.0 Reference: Exhibit B-1, pp. 26, 156, 232, 236, 263-264

2014 – 2018 Annual Reviews

"The costs of the Annual Review will be recorded in a deferral account, which the Company proposes to amortize into rates in the subsequent year." (p. 264)

"FBC is not forecasting a change to the staffing level in the Regulatory department over the forecast period." (p. 156)

"The two most commonly cited benefits of a PBR plan are its effectiveness in incenting the utility to capture efficiencies, and regulatory efficiency." (p. 26)

192.1 For each of 2012 and 2013, please provide a breakdown of the approved and actual (projected actual, in the case of 2013) O&M related to recurring regulatory costs, with an explanation for the activities associated with those costs.

<u>Response:</u>

The 2012 and 2013 approved and actual/projected Regulatory O&M is provided below.

	2012 Approved	2012 Actual	2013 Approved	2013 Projection
Labour	$ 878	$ 869	$ 894	$ 766
Non-Labour	240	284	145	262
Total O&M	$ 1,118	$ 1,153	$ 1,039	$ 1,028

The activities associated with Regulatory O&M expense include the provision of regulatory services such as the preparation of all revenue requirements, cost of capital and rate design applications, applications for CPCNs, energy supply applications and providing interpretation, education and communication of regulatory requirements and policies to departments throughout the Company. These expenses represent the ongoing O&M expense associated with those activities. Incremental expenses incurred for regulatory compliance, including legal fees, expert witnesses and consultants, intervener funding and Commission costs, are captured in deferral accounts as described in Section D4.

192.1.1 Is FBC proposing a sustainable savings adjustment to 2013 Base O&M in anticipation of any regulatory efficiency that is expected during the PBR period? If so, please provide the amount of the sustainable savings adjustment and the departments that it is allocated to.

Response:

No, FBC does not propose any downward adjustment to Base O&M in regard to regulatory efficiency. In regard to the demands of revenue requirements applications, the 2012 and 2013 O&M expense for the Regulatory department, and indeed for Regulatory-related activities in other departments, are already reflective of the level of effort required in the 2007-2011 PBR Plan. The Company did not increase its O&M Expense for 2012 or 2013 despite operating under a cost-of-service revenue requirement in those years. With regard to other types of regulatory applications, FBC has experienced a dramatic increase, not decrease, in regulatory demands throughout the Company, which are not expected to be mitigated by PBR.

192.2 Is FBC proposing to record the variance between approved and actual Annual Review costs in this deferral account, or to record the full cost each year? What was the average cost of these Annual Reviews in the last PBR period?

Response:

Consistent with approved practice, FBC will record the full incremental cost of Annual Reviews in the deferral account. As shown below, the average cost of Annual Reviews in the last PBR Period is $58 thousand. As the 2011 Annual Review was held in conjunction with the 2012-2013 RRA the costs were not separately tracked.

	($000s)
2007 Annual Review	39
2008 Annual Review	43
2009 Annual Review	75
2010 Annual Review	76
Average	58

192.3 Please discuss the challenges that FBC anticipates with respect to forecasting the cost of Annual Reviews.

Response:

Costs of Annual Reviews will be reforecast each year and will vary depending on the expected scope of the review process and the specific requirements associated with it. For example, the process for the PBR Mid-Term Review will likely be greater in scope than other Annual Reviews during the period. As a further example, FBC has indicated that it expects to file a depreciation study during the PBR term, which would be filed as part of the Annual Review. While costs of Annual Reviews will vary year to year, to the extent the scope and requirements of such reviews are well understood, FBC should be able to reasonably forecast the costs.

192.4 Please provide the actual annual cost incurred for the Annual Review process for each year of the previous PBR period.

Response:

Please refer to the response to BCUC IR 1.92.2.

193.0 Reference: Exhibit B-1, pp. 265, 269-270; Order G-163-12

On-Bill Financing (OBF) Pilot Program

Order G-163-12 notes the following:

"3. FBC is approved to establish two new non-rate base deferral accounts:

(i) DSM Deferral Account: a new non-rate base DSM deferral account attracting AFUDC, to capture, on a net-of-tax basis: the OBF Pilot Program costs including any regulatory application costs, the interest rate buy-down adjustment to be recovered from all customers, and loan defaults and bad debts not captured by the Loan Loss Reserve Fund. Effective January 1, 2015, this account is approved to be transferred into rate base with an amortization period of 10 years beginning on January 1, 2015, for recovery from all customers; and

(ii) OBF Financing Deferral Account: a new non-rate base deferral account attracting AFUDC, to capture, on a net-of-tax basis, the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries."

"Pursuant to Order G-163-12 FBC will transfer the balance of this account to rate base effective January 1, 2015. The Company proposes to change the amortization period of this account from 10 years to 15 years, consistent with the proposed amortization period of its DSM expenditures beginning January 1, 2015." (p. 265)

"FBC is seeking approval to transfer the balance of [the On-Bill Financing (OBF) Participant Loans deferral] account as at December 31, 2014 to rate base on January 1, 2015 and to continue to recover the balance from OBF pilot program customers over approximately a ten year period (the loan repayment period) until the account is fully recovered." (p. 270)

193.1 Please elaborate on why, in FBC's opinion, it is appropriate to extend the amortization beyond the ten years approved by Order G-163-12 to 15 years.

<u>Response:</u>

In Exhibit B-1-1, Section 8.1, pp.18-19; Appendix H, FBC seeks approval to increase its DSM amortization period from 10 years to 15 years based on information in Table H-6. This increase in amortization period is also consistent with the amortization treatment of BC Hydro's DSM expenditures, as approved by Order G-77-12A. In FBC's opinion, it is appropriate to have the same amortization period for all FBC DSM programs, as the proposed 15 year period is based on a weighted average of Effective Measure Lifetime (EML) for the FBC DSM portfolio (Table H-

6). The measures included in the OBF Pilot Program are the Building Envelope and Heat Pumps included in the Residential Programs in Table H-6 and both have Effective Measure Lifetimes (EML) that are greater than 15 years (25 and 20 respectively).

Taking into consideration consistency in amortization periods and that the OBF Pilot Program measures have EMLs above the average EML for FBC's DSM programs, it is appropriate to extend the amortization period for the OBF Pilot Program costs to 15 years.

193.1.1 Specifically, please discuss why FBC proposes an amortization period for this deferral account that varies from the ten year amortization period proposed for the On-Bill Financing (OBF) Participant Loans deferral account.

Response:

FBC proposes an amortization period for the OBF Pilot Program Deferral Account that varies from the ten year amortization period proposed for the OBF Participant Loans deferral account (also referred to as the OBF Financial Deferral Account, above), because they are different types of costs. While they are both in non-rate base deferral accounts, the OBF Pilot Program costs are DSM program costs and therefore should be amortized over the same time period as the other DSM program costs. The OBF Participant Loans Deferral Account amortization will appropriately be matched to the loan amortization period.

193.2 Please provide a continuity schedule of the On-Bill Financing (OBF) Pilot Program deferral account in the same format as Table 1-B of Exhibit B-1 from inception to December 31, 2014.

Response:

Below is a continuity schedule of the On-Bill Financing (OBF) Pilot Program deferral account from inception to December 31, 2014.

	Balance at Dec. 31, 2011	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amort.	Balance at Dec. 31, 2012
				($000s)				
On Bill Financing (OBF) Pilot Program	-	37	0	(9)	-	-	-	28
On Bill Financing (OBF) Part. Loans	-	-	-	-	-	-	-	-
	-	**37**	**0**	**(9)**	**-**	**-**	**-**	**28**

	Balance at Dec. 31, 2012	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amort.	Balance at Dec. 31, 2013
				($000s)				
On Bill Financing (OBF) Pilot Program	11	26	2	(7)	-	-	-	32
On Bill Financing (OBF) Part. Loans	-	220	7	(57)	-	-	-	170
	11	**246**	**9**	**(64)**	**-**	**-**	**-**	**202**

	Balance at Dec. 31, 2013	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amort.	Balance at Dec. 31, 2014
				($000s)				
On Bill Financing (OBF) Pilot Program	32	34	4	(9)	-	(3)	-	57
On Bill Financing (OBF) Part. Loans	170	240	21	(65)	(17)	(5)	-	344
	202	**274**	**25**	**(75)**	**(17)**	**(8)**	**-**	**402**

193.3 Please provide a breakdown of the forecast and actual annual On-Bill Financing (OBF) Pilot Program costs for each of 2012, 2013 and 2014.

Response:

The table below shows the forecast and actual annual On-Bill Financing (OBF) Pilot Program costs for each of 2012, 2013 and 2014.

	2012 (Forecast)	2012 (Actual)	2013 (Forecast)	2014 (Forecast)
OBF Pilot Program costs	$ 52,726	$ 14,663	$ 26,246	$ 33,664

The 2012 actual figure in the table above does not match the 2012 actual figure in the response to BCUC IR 1.193.2 because payment of $21,994.56 for the FEU portion of the Program costs should have been accrued to 2012. When the payment ($ 21,994.56) is subtracted from the

2012 actual figure in response to BCUC IR 1.193.2 (~$37 thousand), it yields the 2012 actual figure in the table above.

193.4 Would FBC agree that this account may not serve the purpose of controlling rate variability or allocating cost incidence to the appropriate customers in a timely way? Why or why not?

Response:

The Company is unsure which deferral account the question refers to; the OBF Pilot Program deferral account or the OBF Participant Loans deferral account.

Regardless, the Company believes that each of the two accounts, both serve to control rate variability and to allocate cost incidence to the appropriate customers.

With respect to the OBF Pilot Program deferral account, an amortization period of 15 years serves to both mitigate rate variability by allocating the cost of the program over the weighted measure life of FBC's DSM portfolio to which the program applies, and allocates costs to all customers since any customer can take advantage of the program.

With respect to the OBF Participant Loans deferral account, an amortization period of 10 years also serves to both mitigate rate variability by allocating the cost of the program over the loan repayment period and allocates costs to only those customers that take advantage of the program.

194.0 Reference: Exhibit B-1, pp. 159, 265; Order G-110-12

2014-2018 PBR Application

"This account was established by Order G-110-12…" (p. 265)

Order G-110-12 notes the following:

"FortisBC is seeking approval to defer what it expects to be costs in the amount of $0.08 million ($0.1 million before tax) for its 2014 Revenue Requirements Application in 2013… The Commission Panel is of the view that these regulatory expenses are operating costs and should be capable of being absorbed into rates without deferral. However, given that the treatment requested accords with what has been done in the past, the Panel is prepared to approve this item as a non-rate base deferral account for rate-smoothing purposes."

194.1 For each of 2011, 2012 and 2013, please provide the approved and actual (projected actual, in the case of 2013) O&M related to the 2012-2013 RRA and ISP Application.

Response:

FBC is not able to provide the O&M related to the 2012-2013 RRA and ISP application. All regular labour associated with the preparation of and regulatory applications are absorbed in the O&M Expense of various departments, without being specifically tracked.

The costs referred to in the preamble to this question are for deferred incremental costs only such as 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, and incremental labour (such as overtime for bargaining unit employees).

Incremental (deferred) costs related to the 2012-2013 RRA and ISP application were:

($000s)	
2011	$1,519
2012	886
2013	-
Total	**$2,405**

194.1.1 Please confirm if the costs provided above are included in the O&M summary in Table C4-27.

Response:

No. These costs are incremental, and their nature is identified in the response to BCUC IR 1.194.1.

194.2 Please discuss the pros and cons of amortizing the 2014-2018 PBR Application deferral account over a period of time less than the proposed five years.

Response:

When considering the amortization period to be requested for a deferral account, FortisBC considers the size of the balance in the deferral account, the nature of the deferral, any applicable benefit period of the deferral, and the impact on customer rates in determining over how many years a deferral account balance should be amortized. This information is considered in the context of the overall rate increase for the test period.

FBC proposed a five-year period for the amortization of this account because it aligns the period of the recovery with the benefit period, which is the term of the PBR Plan. Nevertheless, an amortization period other than five years could also be used.

194.3 Please provide a breakdown of the actual costs incurred to date and the forecast costs associated with the 2014-2018 PBR application, with an explanation of the activities associated with the costs.

Response:

Current and forecast costs as of the date of application are summarized in the following table.

The cost estimates assumed that the Application would be disposed of by way of a Negotiated Settlement Process. Commission Order G-151-13 set down an oral public hearing for review of a portion of the Application. FBC will update its cost estimates in its October 18, 2013 Evidentiary Update.

Deferred costs of Regulatory Compliance accounts include legal fees, costs for expert witnesses and consultants, intervener and participant funding costs, Commission costs, required public notifications, staff travel expenses, miscellaneous facilities, stationery and supplies costs, and incremental labour (such as overtime for bargaining unit employees).

	Current	Forecast
	($000s)	
BCUC and Intervener Costs	-	225
Legal Fees	10	50
Consulting Fees	75	150
Staff and Other Expenses	24	75
Total Expenditure	109	500
Income Tax Effect	(27)	(125)
Net Expense	81	375

Note: Excludes financing costs.

194.3.1 Please provide an explanation for any variance between the $0.08 million after tax approved by Order G-110-12 and the actual and forecast costs provided in the aforementioned IR.

Response:

The Company provided a conservative estimate of the costs of a 2014 Revenue Requirements Application in the 2012-13 RRA. At the time of filing, FBC had not determined the type of application, test period, or content of an application that would be filed for 2014.

The cost estimates presented in this Application reflect a five-year PBR application to be disposed of through a Negotiated Settlement Process.

FBC intends to file an updated cost estimate in its October 18, 2013 Evidentiary Update to reflect the regulatory process set out in Order G-151-13.

195.0 Reference: Exhibit B-1, p. 266; Order C-4-13

City of Kelowna Acquisition Customer Benefit

195.1 Please provide a breakdown of the gross 2013 Customer Benefit, the adjustment to the 2013 Revenue Variance account and the net 2013 Customer Benefit related to the City of Kelowna acquisition.

<u>Response:</u>

The Customer Benefit of $2,610k in 2014 Revenue Requirements is a derivative of Rate Stabilization due to the COK Acquisition in 2013 (C-4-13) to maintain customer rates at the pre-approved (G-110-12) level of 4.2%.

The Table below shows the derivation of the amount.

Revenue Requirement P[rameters	Forecast C-4-13 (With COK) 2013	Previous Approval G-110-12 (Without COK) 2013	Variance (Stand Alone COK Impact) 2013	Remarks
		($000s)		
Revenue Requirements				
Power Purchases	91,942	91,942	-	
Water Fees	9,871	9,871	-	
O&M Expense	57,621	56,277	1,344	
Capitalized Overhead	(11,524)	(11,255)	(269)	
Wheeling	5,233	5,233	-	
Other Income	(7,165)	(7,165)	-	
Property Taxes	15,085	15,085	-	
Income Taxes	7,666	7,022	644	
Cost of Debt	42,377	41,125	1,252	
Cost of Equity	47,665	46,447	1,218	
Depreciation and Amortization	51,090	51,091	(1)	
Flow Through Adjustments	(1,941)	(1,941)	-	
Revenue Requirement (Prior to COK Adjustment)	**307,920**	**303,732**	**4,189**	
Customer Benefit of Transaction (due to COK Acquisition to reset Rates to the previously Approved Level (G-110-12) of 4.2%	**2,610**	**-**	**2,610**	Will reduce Revenue Requirement in 2014
Total Revenue Requirements	**310,530**	**303,732**		
Less: Revenue at Approved Rates	**298,005**	**291,481**		
Revenue Deficiency for Rate Setting	**12,525**	**12,251**		
Rate Increase	**4.20%**	**4.20%**	**0.00%**	Rate reset to Pre-Approved level

195.1.1 Please confirm, or explain otherwise, that the $2.6 million Customer Benefit represents the benefit net of the adjustment to the Revenue Variance deferral account.

Response:

Confirmed.

195.2 Do the additions to this deferral account agree to the compliance filing filed in response to Order C-4-13? If not, please provide the supporting calculations for this amount.

Response:

Yes, the additions to this deferral account agree to the compliance filing filed in response to Order C-4-13.

196.0 Reference: Exhibit B-1, p. 266

City of Kelowna Acquisition Legal and Regulatory Costs

Order C-4-13 notes the following: "FortisBC must establish a non-rate base deferral account to capture closing, regulatory process and legal costs up to a maximum of $0.5 million. The deferral account shall accrue short-term interest at FortisBC's approved 2013 short-term interest rate of 3.48 percent."

196.1 Please confirm, or explain otherwise, that FBC is requesting rate base treatment for the City of Kelowna Acquisition Legal and Regulatory Costs deferral account.

Response:

Confirmed. FBC is requesting rate base treatment for the deferred accounts listed in sections D4.3 to D4.6. The request for rate base treatment is set out in detail in section D3.2. Note that in the City of Kelowna Phase 2 proceeding, FortisBC has also asked that the cap of $0.5 million set in Order C-4-13 be lifted or determined to be inapplicable to Phase 2 in order to permit recovery of Phase 2 costs.

196.1.1 If the preceding IR is confirmed, please discuss why FBC proposes to alter the financing costs as directed in Order C-4-13.

Response:

As explained in Section D3.2, the application of deferral account financing arising from Order G-110-12 (and which FBC assumes was the basis for the treatment ordered in C-4-13) is incorrect and that the proper treatment of deferral accounts in the majority of circumstances, including the City of Kelowna Acquisition Legal and Regulatory Costs, is rate base inclusion.

196.2 Please provide a breakdown of the actual closing, regulatory and legal costs incurred related to the City of Kelowna acquisition.

Response:

The costs incurred are summarized in the following table.

	($000s)
BCUC and Intervener Costs	73
Legal Fees	443
Consulting Fees	10
Staff and Other Expenses	82
Total Expenditure	608
Income Tax Effect	(152)
Net Expense	456

Note: Excludes financing costs and costs related to Phase 2 of the City of Kelowna proceeding.

Please refer to the response to BCUC IR 1.196.1.

197.0 Reference: Exhibit B-1, p. 266

2014-2018 Capital Expenditure Plan

Order G-110-12 notes that: "FortisBC expects to spend $0.8 million on preliminary investigation and engineering costs for its 2014-2015 Capital Plan. FortisBC proposes to include these costs in the capital projects for those years…Because they relate directly to the preparation of a required regulatory plan, the Commission Panel views these expenditures as regulatory expenses. The Commission Panel directs that this deferral account attract an interest financing charge at FortisBC's WACD."

197.1 Please discuss why FBC proposes a two year amortization period for this deferral account.

Response:

FBC explains the factors that it considers in proposing an amortization for deferred accounts in its response to BCUC IR 1.194.2.

197.2 Please provide the actual preliminary engineering costs incurred related to the 2014-2018 Capital Expenditure Plan.

Response:

FBC has incurred approximately $361 thousand of preliminary engineering costs to the end of July 2013. Note that this amount only includes incremental costs associated with developing the 2014-18 Capital Plan. Examples of these incremental costs include labour and expenses for external contractors and consultants, and internal labour for positions which are seconded specifically for development of the plan. Costs associated with internal staff who are normally involved in capital planning activities are absorbed in existing O&M and capital standing order budgets; the specific costs for the development of the 2014-18 Capital Plan are not tracked separately in these budgets.

FBC notes that while the Commission appears to have concluded in Order G-110-12 that these costs were incurred only for the purpose of a regulatory proceeding, this is not the case. The majority of the costs are for internal capital planning purposes and would be required whether or not the capital plan was required to be submitted to the Commission.

198.0 Reference: Exhibit B-1, p. 267; Exhibit A2-3 FBC's Application to Establish Deferral Accounts, Evidence, and Commission Order G-23-13

Generic Cost of Capital (GCOC) Proceeding

In December 12, 2012, FBC applied to the Commission for Approval to establish six new deferral accounts. Exhibit A2-3 contains a series of documents related to this matter (the FBC Deferral Account Application, Commission Staff IRs and responses by FBC, and the Commission Decision G-23-13)

198.1 Relating to the GCOC Proceeding, please provide a breakdown of actual costs incurred to date and forecast costs for each of 2012, 2013 and 2014, with an explanation of the activities associated with the costs.

Response:

Current and forecast costs as of the date of application are summarized in the following table.

	2012	2013 YTD	2013 F	2014F
		($000s)		
BCUC and Intervener Costs	-	5	120	-
Legal Fees	13	-	120	
Consulting Fees	-	37	150	
Staff and Other Expenses	3	-	10	-
Total Expenditure	16	42	400	-

Note: Excludes financing costs.

198.1.1 Please provide the reasons for any variance between the total costs provided in the preceding IR, and the forecast costs included in the December 12, 2012 Deferral Account Application of $400,000 before tax.

Response:

Response:

The forecast costs are consistent with those in the December 12, 2012 Deferral Account Application.

FBC intends to review its estimate of costs to complete the GCOC proceeding and may file an updated cost estimate in its October 18, 2013 Evidentiary Update.

198.2 Please provide any additional information available subsequent to Order G-23-13 dated February 8, 2013 that supports the justification for the recovery of these costs.

Response:

FBC submits that the deferral of the GCOC proceeding costs was fully justified in the December 12, 2012 application. FBC did not apply for disposition of the deferral account at the time.

The costs of FBC's participation in the GCOC are necessary and prudent. The Company filed its application for deferral of the costs in a manner consistent with past practice as approved by the Commission, as documented in detail during the regulatory process following the Company's December 12, 2012 application to establish the deferral accounts. There is no basis on which to deny recovery of these costs.

FBC states that "FBC will incur costs related to the Stage 1 and Stage 2 processes in 2013 and 2014, and proposes to amortize the account over two years beginning in 2014." (p. 267)

198.3 Would it not be appropriate to recover the prudently incurred costs of these proceedings over the expected duration of the GCOC (3-5 years) or the life of FBC's proposed PBR?

Response:

FBC does not believe it is appropriate to recover the prudently incurred costs over the life of FBC's proposed PBR, which is requested to be five years. To clarify, the expected duration of the GCOC is more appropriately considered to be two years based on BCUC Order G-75-13 which states:

> *"FEI is directed to file an application for the review of the common equity component and the ROE approved in Paragraphs 1 and 2 of this Order by no later than November 30, 2015."*

Given that FBC will likely incur new costs related to that Cost of Capital proceeding in 2015 or 2016 and that a new benchmark ROE or equity structure may be applicable to FBC after that proceeding, it is appropriate to amortize the balance of this deferral account over the time period to which the existing decision will be applicable, namely 2014 and 2015.

199.0 Reference: Exhibit B-1, p. 267; Exhibit A2-3 FBC's Application to Establish Deferral Accounts, Evidence, and Commission Order G-23-13

BCUC Inquiry into the Mandatory Reliability (MRS) Program

199.1 Please provide a breakdown of actual costs incurred to date and forecast costs related to the BCUC Inquiry into the MRS program for each of 2012, 2013 and 2014, with an explanation of the activities associated with the costs.

<u>Response:</u>

Deferred costs of Regulatory Compliance accounts include legal fees, costs for expert witnesses and consultants, intervener and participant funding costs, Commission costs, required public notifications, staff travel expenses, miscellaneous facilities, stationery and supplies costs, and incremental labour (such as overtime for bargaining unit employees).

The costs incurred to date for this process are summarized in the following table.

	2012	2013	Total
		($000s)	
Commission Expense	-	-	-
Legal Fees	-	46	46
Consulting Fees	-	17	17
Staff and Other Expense	1	-	1
Total Expenditure	1	63	64
Income Tax Effect	(0)	(16)	(16)
Net Expense	0	47	48

Note: Excludes financing costs

FBC has forecast total expenditures of $75 thousand (after tax and excluding financing costs) for this regulatory proceeding.

199.1.1 Please provide the reasons for any variance between the total costs provided in the preceding IR, and the forecast costs included in the December 12, 2012 Deferral Account Application of $100,000 before tax.

Response:

To date, FBC has incurred lower than forecast legal fees for its participation in the MRS Inquiry.

The Company notes that Commission Order R-33-13 was issued September 17, 2013. The Company is currently reviewing the Order to determine if there are any additional impacts to FBC.

199.2 Please provide any additional information available subsequent to Order G-23-13 dated February 8, 2013 that supports the justification for the recovery of these costs.

Response:

FBC submits that the deferral of the MRS Inquiry proceeding costs was fully justified on its application of December 2012. FBC did not apply for disposition of the deferral account at the time.

The costs of FBC's participation in the MRS Inquiry are necessary and prudent. The Company filed its application for deferral of the costs in a manner consistent with past practice as approved by the Commission, as documented in detail during the regulatory process following the Company's December 12, 2012 application to establish the deferral accounts. There is no basis on which to deny recovery of these costs.

FBC states that "FBC proposes to amortize the costs of participating in the Inquiry in 2014." (p. 267)

199.3 Would it not be appropriate to recover the prudently incurred costs of participating in this MRS Inquiry over several years (perhaps three years) to recognize the multi-year nature of the Inquiry into this ongoing program?

Response:

FBC explains the factors that it considers in proposing an amortization for deferred accounts in response to BCUC IR 1.194.2. FBC forecasts the costs of this account to be $78 thousand (after tax).

199.4 Please confirm that no internal Utility costs are part of this deferral account.

Response:

No internal labour costs are included in the deferral account. Deferral accounts related to Regulatory Compliance, as described in Section D4 at page 259 of the Application, consist of 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, and incremental labour (such as overtime for bargaining unit employees).

200.0 Reference: Exhibit B-1, p. 268; Exhibit A2-3 FBC's Application to Establish Deferral Accounts, Evidence, and Commission Order G-23-13

Mandatory Reliability Standards Audit

"Of the approximate costs incurred during the audit process, about $231,000 of internal labour costs were charged to Operating and Maintenance (O&M) expense as budgeted in the 2012 Revenue Requirements. The balance of the audit expenses, were recorded in a deferral account ($0.4 million net of tax). FBC requests approval to amortize the deferred amounts in 2014." (p. 266)

200.1 Please discuss if the $231,000 labour costs charged to O&M were budgeted in the 2012 Revenue Requirements specifically for the MRS audit.

Response:

The $231,452 of internal labour costs were incurred by individuals whose time was already accounted for in the Company's O&M Expense as approved by Order G-110-12, which is already being recovered in 2012 and 2013 approved rates.

FBC had previously budgeted $75 thousand annually for conducting self-certification, spot audits/checks and participating in BCUC / WECC formal audits; a specific allowance for the July 2012 audit was not separated out. This participation was to include FBC audits as well as participation as an observer on audits of other entities. Based on recent experience, FBC has determined that self-certification costs approximately $150 thousand annually and thus has adjusted this forecast cost. The costs of future FBC official audits (with the BCUC / WECC) will be incremental to future budgets.

200.2 Please discuss if there was a corresponding reduction of labour costs charged to O&M in 2013 and beyond to reflect the fact that the MRS audit was a non-recurring cost. If yes, please provide the amount of any cost reductions. If not, please explain why not.

Response:

There was no corresponding reduction to O&M. Please refer to the response to BCUC IR 1.200.1. The official BCUC/WECC audits in 2015 and 2018 will also be incremental to the O&M.

200.3 Please provide a breakdown of actual costs incurred related to MRS Audit and an explanation for the activities related to those costs.

Response:

Following is a a breakdown of the audit costs that were submitted on December 12, 2013

Incremental Labour Costs	
MRS (Overtime only)	$ 6,673
Project Management/ Administration	74,924
Information Technology	70,591
Legal/Internal Audit	7,264
Operations/ Vegetation Management	24,001
System Control Centre	37,651
Engineering/ Planning	124,114
Generation	30,375
Facilities	8,148
Security	16,653
Consulting Fees	126,771
Non-Labour Expenses	48,140
Total Deferred Expenditures	$ 575,306
Labour Charged to O&M	231,452
Total Audit Expense	$ 806,759

Year end reconciliation resulted in a total deferred expenditure of $571,271, a difference of $4,035.

The Audit covered, at a minimum, all of the Reliability Standards that were part of the 2012 BCUC and WECC Implementation Plan for Monitoring Compliance with British Columbia Reliability Standards that are applicable to the functions that FortisBC is registered for (10 of 12 functions). The 2012 Implementation Plan was issued by Commission Order G-194-11 on November 28, 2011 and re-issued by Commission Order G-194-11A on February 24, 2012. The Audit notification was received on April 23 and the Audit concluded August 2. The Audit covered the period from November 1, 2010 to August 2, 2012. FortisBC was required to prove compliance with each standard and requirement as part of the Audit scope for each of the years 2010, 2011, and 2012. The Compliance Pre-Audit survey was submitted to WECC May 24. The pre-audit data requests and the Reliability Standard Audit Worksheets (RSAWs), with supporting evidence, were submitted to WECC June 22, 2012. Data requests, which ranged from interviews and tours, to submission of additional evidence and back-up verification of evidence, were subsequently processed to August 1.

WECC's audit objectives were to review and validate compliance with the reliability standards applicable to FortisBC, and to validate evidence of self-reported violations, previous self-certifications and to review the status of any mitigation plans. The WECC audit team was comprised of sixteen individuals, eight of whom travelled and conducted the on-site audit. WECC provided in advance a request for documents to be delivered to them 20 days prior to the on-site audit. The 2012 on-site audit included in-person interviews, document requests as well as field visits and inspections to assess FortisBC's physical and cyber security compliance. These visits were to control center facilities, computer rooms, generating stations, and substations, as well as reviews of physical security perimeters, electronic security perimeters, critical cyber assets and both physical and cyber access control and monitoring devices.

FortisBC learned that the WECC audit approach for each standard would require not only proof that the task(s) required under the standard occurred but also that evidence could be required for every aspect of the performance set out in the standard. As an example, if a standard indicated that FortisBC "shall develop and implement a Corrective Action Plan to avoid future misoperations" then the audit evidence would be the actual Corrective Action Plan document as well as proof that the plan was implemented and operating. It became clear that the preparation for the WECC audit involved not just knowing that the Company could demonstrate compliance, and confirmation that all evidence exists, but also being able to produce evidence promptly on request. Additionally, it became clear during the preparation process that the evidence for MRS audits involved greater corroborating aspects than other internal or external audits FortisBC had historically participated in. Once the level of evidence requirements was learned, internal efforts to prepare, review and organize evidence in advance of the audit were conducted. FortisBC personnel verified that all evidence was of the highest quality and that all documentary details were present (title, purpose effective date, revision history, approval date and authorizing signatures). Examples of evidence requirements that go beyond the needs of other standard audits are voice recordings, questionnaires, emails, logs, data sheets, planning and other studies and letters of attestation.

The audit notification identified 105 requirements that were being audited with over 600 questions requiring answers and supporting evidence. FortisBC provided over 500MB of information and expended over 8,700 labour hours during the audit period. The audit required the participation of approximately 50 FortisBC employees (to varying degrees of involvement). This represents almost 10 percent of the total organization.

200.3.1 Please provide an explanation for any variance between the total costs provided in the preceding IR, and the forecast costs included in the December 12, 2012 Deferral Account Application of $806,759.

Response:

Reconciliation at year-end resulted in a negative variance of $4 thousand.

200.4 Please provide any additional information available subsequent to Order G-23-13 dated February 8, 2013 that supports the justification for the recovery of these costs.

Response:

FBC submits that the recovery of the MRS costs was fully justified on its application of December 2012.

FBC's participation in the MRS audit was required in order to demonstrate compliance with the MRS Program, and the costs incurred were necessary and prudent. The Company filed its application for deferral of the costs in a manner consistent with past practice as approved by the Commission, as documented in detail during the regulatory process following the Company's December 12, 2012 application to establish the deferral accounts. There is no basis on which to deny recovery of these costs.

200.5 Should the costs allocated to this account be reduced by an amount to recognize the average annual costs of FBC's participation in WECC's voluntary program prior to BC's MRS?

Response:

No, the costs to maintain full and auditable compliance with the BC Mandatory Reliability Standards are incremental to the organization. They are required in addition to the previous effort of best practices. The previously voluntary WECC Reliability Management System (RMS) had limited scope and focused primarily on operational concerns. The costs associated with participation in the RMS were low and were included within previous approved budgets. This effort was not specifically tracked and cannot be separated from other expenditures in previous years.

200.6 Please confirm that the costs allocated to this account are for external consulting and legal costs only and do not include internal FBC operating expenses.

Response:

Only incremental expenses were charged to the deferral account; this includes labour costs arising from overtime, backfilling of positions, and positions normally charged to capital projects or capital loading pools, in addition to consulting fees and non-labour expense not budgeted in the 2012 – 2013 Revenue Requirements Application.

200.7 Since these audits are multi-year in nature, shouldn't the prudently approved costs be recovered over the time between audits?

Response:

Please refer to the response to BCUC IR 1.194.2 which explains the factors that FBC considers when proposing an amortization period for deferred charges.

201.0 Reference: Exhibit B-1, p. 268; Exhibit A2-3 FBC's Application to Establish Deferral Accounts, Evidence, and Commission Order G-23-13

Mandatory Reliability Standards – Operating and Maintenance Expense 2012 – 2013

"FBC's approved O&M Expense for 2012 and 2013 included $1.2 million in each year to maintain full and auditable compliance with the BC MRS." (Exhibit B-1, p. 268)

"During 2012 the Company recorded an additional $0.3 million before tax of costs in the deferral account; in 2013 the incremental cost required to ensure that MRS compliance is maintained are estimated to be $0.9 million before tax." (Exhibit A2-3)

"Also contributing to increased O&M costs is the completion of the mitigation plans required to achieve initial compliance with standards, which were largely exempt from self-reporting and self-certification while under mitigation. 2013 is the first year in which the Company will not have a significant percentage of the requirements under mitigation, which increases the requirements for "24/7" compliance monitoring." (Exhibit A2-3)

201.1 Please provide a breakdown of the approved and actual costs incurred to maintain full and auditable compliance with BC MRS in each of 2011, 2012 and 2013, with an explanation of the activities related to these costs.

Response:

The requested breakdown is provided in the following table:

	2011	2012	2013
Approved	$0.9M	$1.2M	$1.2M
Actual[1]	$1.0M	$1.5M	$2.1M

[1] *Includes deferred expenditures of $320 thousand in 2012 and $900 thousand in 2013*

The additional effort related to MRS is a combination of increased tasks and a more comprehensive understanding of the requirements for ensuring compliance to the auditable level. Information obtained from consultants further developed FBC's understanding of the magnitude of effort required to maintain compliance.

Since the 2012-13 RRA, FBC's understanding and interpretation of the effort necessary to meet the requirements of MRS has indeed changed, not only as a result of the audit itself but also through the Company's participation in user group meetings and through consultation with consultants and other utilities. Completion of the tasks previously identified requires more detail and effort, including changes to the expected processes as well as an increased frequency of review, than initially expected.

201.2 Please provide any additional information available subsequent to Order G-23-13 dated February 8, 2013 that supports the justification for the recovery of these costs.

Response:

FBC submits that the materials filed in its December 12, 2012 application for approval of the deferral account fully justifies the recovery of the costs. The record of the December 12, 2012 application is found at Exhibit A2-8.

FBC's costs related to the BC MRS Program are necessary and prudent. Participation in the program is not optional and as explained in detail in both the December 12, 2012 application and in Section C4.10 of the Application, the requirements of the program and the associated costs continue to evolve. FBC further submits that there is no basis on which to deny recovery of these costs.

202.0 Reference: Exhibit B-1, p. 269

Revenue Variance

"Order C-4-13 approved an adjustment to the revenue variance arising from the City of Kelowna acquisition. FBC will amortize the additions approved by Order C-4-13 during 2014."

Order C-4-13 notes that: "FortisBC's request for an increase to the 2013 base revenues for revenue flow-through mechanism purposes is approved subject to a compliance filing which incorporates all of the above adjustments."

202.1 What is the amortization period for the Revenue Variance deferral account for any additions, other than those related to the City of Kelowna acquisition?

<u>Response:</u>

Order G-110-12 approved an amortization period of one year for the Revenue Variance Deferral Account.

202.2 Please provide the 2013 additions to the Revenue Variance deferral account related to the City of Kelowna acquisition only.

<u>Response:</u>

FBC is unable to provide this information because the Company does not segregate the revenue of customers previously served by the City of Kelowna. FBC can provide the following breakdown of the 2013 Revenue Variance.

		($000s)
2013 Approved Revenue per BCUC Order G 110-12	A	303,732
City of Kelowna Revenue per BCUC Order C-4-13	B	6,799
Total 2013 Approved Revenue	**C=A+B**	**310,531**
Projected Revenue 2013	D	304,875
Projected Revenue Variance 2013	**E=C-D**	**5,656**
Less Income Tax	F	(1,414)
Projected 2013 Revenue Variance 2013 (after tax)	**G=E+F**	**4,242**

(see Exhibit B-1, Section E, Page 299, Line 5)

202.2.1 Do the additions related to the City of Kelowna agree to the compliance filing filed in response to Order C-4-13? If not, please provide the supporting calculations for this amount.

Response:

FBC confirms that the additions agree to the compliance filing.

202.3 Please provide the supporting calculations for the 2012 and 2013 additions to the deferral account other than those related to the City of Kelowna acquisition. Please include the following details:

- Variance in use per customer account;
- Variance in customer count;
- Any other applicable variances.

Response:

FBC is unable to provide this information because the Company does not segregate the revenue of customers previously served by the City of Kelowna. FBC can provide the following information for its total customer base.

Revenue Related Parameters	Revenue ($000S)	Sales GWh	Average Customer Count	Sales MWh per Customer	Revnue per Customer ($000S)
2012 Approved	287,445	3,193	115,041	27.76	2.50
2012 Actual	282,943	3,144	113,588	27.68	2.49
2012 Variance	**(4,503)**	**(49)**	**(1,453)**	**(0.08)**	**(0.01)**
2013 Approved	310,531	3,233	124,603	25.94	2.49
2013 Forecast	304,875	3,189	121,566	26.23	2.51
2013 Variance	**(5,655)**	**(44)**	**(3,037)**	**0.29**	**0.02**

Note: Minor variances due to Rounding.

203.0 Reference: Exhibit B-1, pp. 269-270

On-Bill Financing (OBF) Participant Loans

Order G-163-12 notes the following:

"3. FBC is approved to establish two new non-rate base deferral accounts:

(iii) DSM Deferral Account: a new non-rate base DSM deferral account attracting AFUDC, to capture, on a net-of-tax basis: the OBF Pilot Program costs including any regulatory application costs, the interest rate buy-down adjustment to be recovered from all customers, and loan defaults and bad debts not captured by the Loan Loss Reserve Fund. Effective January 1, 2015, this account is approved to be transferred into rate base with an amortization period of 10 years beginning on January 1, 2015, for recovery from all customers; and

(iv) OBF Financing Deferral Account: a new non-rate base deferral account attracting AFUDC, to capture, on a net-of-tax basis, the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries."

203.1 Please provide a continuity schedule of the On-Bill Financing (OBF) Participant Loan deferral account in the same format as Table 1-B of Exhibit B-1 from inception to December 31, 2014.

Response:

Please refer to the response to BCUC IR 1.193.2.

203.2 Please provide a breakdown of the actual and forecast annual On-Bill Financing (OBF) Participant Loans costs for each of 2013 and 2014.

Response:

Please refer to the response to BCUC IR 1.193.3.

203.3 Please provide details on the terms of the participant loans provided to the OBF pilot program customers, including interest rates and the repayment terms.

Response:

OBF Loans will carry the 4.5 per cent rate prescribed by regulation, and are paid off in monthly installments over a 10 year term.

Full OBF terms and conditions can be viewed at the following link:

http://www.fortisbc.com/Electricity/PowerSense/IncentivesPrograms/EfficiencyLoanProgram/Documents/EfficiencyLoanProgram_TC_Jan13.pdf

203.3.1 Please discuss why, in FBC's opinion, it is appropriate to earn a rate base return on this deferral account balance, in addition to collecting any applicable interest charges from the participating customers.

Response:

While the balance in this account will be reduced by principal and interest repayments, there will still be a balance outstanding at year-end. Consistent with the Uniform System of Accounts, and as noted in Section D3, page 249 of the 2014-2018 PBR Application, items that are recoverable from customers but not included in rate base (such as non-rate base deferral accounts) are financed at the Weighted Average Cost of Capital so that the utility is afforded the opportunity to earn a fair return on costs prudently incurred to provide service to customers. In addition, the interest collected from customers is a credit to the deferral account balance therefore the collection of interest from customers is reducing the balance of the deferral for which FBC would earn a rate base return on. The approval of this treatment was provided previously in Order G-163-12 of the OBF Application.

204.0 Reference: Exhibit B-1, pp. 270

Kelowna Bulk Transformer Capacity Addition Project

"The Company undertook preliminary engineering for the Kelowna Bulk Transformer Capacity addition project in 2011 and 2012… Since that time, updated load projections have deferred the need for this project from 2015 to 2019…" (p. 270)

204.1 Please provide the additions to this deferral account in each of 2011 and 2012. If these additions are in excess of those approved by Order G-110-12, please explain why.

Response:

Additions to the deferral account for this project are comprised of $0.198 million in 2011 and $0.123 million in 2012 (including deferred interest), which is consistent with the forecast of approximately $0.3 million for preliminary engineering for the project as provided in the 2012-2013 RRA.

204.2 Please discuss if the preliminary engineering performed in 2011 and 2012 will be used as part of the 2019 CPCN or if FBC anticipates that additional costs will be incurred for preliminary engineering.

Response:

As indicated in section C5.7.1, FBC intends to submit a CPCN application 2 – 3 years in advance of the forecast in-service date of 2019 (i.e. CPCN submission in 2016 or 2017). FBC expects that the preliminary engineering already completed will be suitable for reuse at that time. Although no further costs are anticipated for preliminary engineering, there may be some additional costs incurred to update the AACE Class 3 estimate with then current costs, as well as to reconfirm that the assumptions incorporated in the preliminary engineering are still valid. FBC notes that there will also be costs for the future CPCN filing related to public consultation and the regulatory process.

205.0 Reference: Exhibit B-1, p. 270

Section 71 (Waneta Expansion Capacity Agreement Application)

"The deferred costs also include expenditures arising from an application for reconsideration of E-29-10 filed by the Industrial Customers Group on November 10, 2011."

205.1 Please provide a breakdown of additions to this deferral account related to the original 2010 Application in each of 2010, 2011, 2012 and 2013, with an explanation of the activities associated with the costs.

Response:

The deferred costs related to the WAX CAPA application and completion of the associated agreements consist of legal fees, consulting costs, Commission costs, incremental labour, staff expense and miscellaneous facilities, stationery and supplies. Costs related to the WAX CAPA proceeding are summarized in the table below.

	2010	2011	2012	2013	Total
			($000s)		
Commission Expense	-	2	-	-	2
Legal Fees	166	194	-	-	359
Consulting Fees	151	4	-	-	156
Staff and Other Expense	28	2	-	-	30
Total Expenditure	345	202	-	-	547
Income Tax Effect					(152)
Net Expense					395

205.2 Please provide a breakdown of additions to this deferral account related to the 2011 reconsideration in each of 2011, 2012 and 2013, with an explanation for the activities associated with these costs.

Response:

The deferred costs related to the reconsideration application consist of legal fees, and Commission cost sand are summarized in the table below.

	2010	2011	2012	2013	Total
			($000s)		
Commission Expense	-	-	6	-	6
Legal Fees	-	-	206	-	206
Consulting Fees	-	-	-	-	-
Staff and Other Expense	-	-	-	-	-
Total Expenditure	-	-	212	-	212
Income Tax Effect					(53)
Net Expense					159

206.0 Reference: Exhibit B-1, p. 270

Negotiation of a New Power Purchase Agreement between BC Hydro and FBC

"Negotiation of the agreement began in 2005, and the FBC forecast costs of $0.2 milllion ($0.3 million before tax). The total costs expected for the negotiation of the new PPA are $0.3 million ($0.4 million before tax)."

206.1 Please confirm, or explain otherwise, the negotiations for the new PPA between BC Hydro and FBC are complete.

Response:

Confirmed, subject to the approval of the New PPA and related agreements.

206.2 Please provide a breakdown of the actual costs incurred for negotiating the new agreement by year, with an explanation for the activities associated with these costs.

Response:

Please see the following table.

	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
					($000s)					
Commission Costs	-	-	-	-	-	1	-	-	-	1
Legal Fees	-	-	-	14	76	3	-	140	61	295
Consulting Fees	-	-	-	-	4	-	29	5	-	37
Staff and Other Expenses	2	1	1	-	7	-	0	-		11
Total Expenditure	2	1	1	14	87	3	29	145	61	343
Income Tax Effect										(79)
Net Expense										264

Staff and Other Expenses include travel expense, incremental labour, and administrative costs.

206.2.1 Does FBC anticipate incurring any additional costs related to the negotiation of the agreement with BC Hydro? Please discuss.

Response:

No, FBC believes the negotiations are complete and that therefore no further negotiation costs will be incurred, subject to the approval of the New PPA and related agreements.

206.3 Please discuss the events that resulted in an increase in forecast costs from $0.2 million to $0.3 million after tax.

Response:

As shown in the response to BCUC IR 1.206.2, the costs are $343 thousand (before tax). The increase in costs is due to the extended amount of time it took to reach agreement with BC Hydro.

207.0 Reference: Exhibit B-1, p. 270

Negotiation of a New Power Purchase Agreement between BC Hydro and FBC

FBC states that “The Company is amortizing the forecast costs of negotiating the new Power Purchase Agreement (PPA) with BC Hydro in 2012 and 2013 as approved by Order G-110-12.”

207.1 If these costs have been incurred since 2005 were any of the costs included in revenue requirements applications in any years since 2004?

Response:

No. The Company first applied to begin recovery of the costs in its 2012-13 RRA.

207.2 Please confirm that the costs allocated to this account are for external consulting and legal costs only and do not include internal FBC operating expenses.

Response:

Please refer to the response to BCUC IR 1.206.2 for a description of the costs. FBC confirms the vast majority of the costs are for external consulting and legal, and that all of the costs are incremental to costs that are normally included in O&M expense.

208.0 Reference: Exhibit B-1, p. 271

Right of Way Encroachment Litigation

"The Company is expecting to defer approximately $0.09 million ($0.12 million before tax) of legal costs incurred by the end of 2013 associated with an ongoing litigation matter with a land developer… Upon resolution of the dispute, any recovered cost will be recorded to the deferral account and the residual is to be amortized into the Company's rates pursuant to Order G-193-08."

With respect to the property services component of the Operation Support department O&M, FBC submits that, "Property Services includes support for property taxation, negotiation of land acquisition, leases and disposal as well as related environmental reviews, maintenance of right of way ("ROW") agreements, and First Nations land negotiations."

FBC submits that the Operation Support O&M costs are $1,205 thousand and $1,252 thousand for 2013 Projection and 2013 Approved, respectively.

208.1 Please confirm if Order G-193-08 relates to an RRA reviewed by way of an oral hearing, written hearing, NSP or SRP.

Response:

Commission Order G-193-08 approved a Negotiated Settlement Agreement in FBC's 2009 Revenue Requirements Application.

208.2 Taking into consideration the variance between approved and projected 2013 O&M costs related to the Operation Support department, please discuss why, in FBC's opinion, the litigation costs of $0.09 million are appropriate for deferral account treatment.

Response:

Please refer to the response to BCUC IR 1.131.2.1 for an explanation of the litigation. The legal costs in this matter were mostly incurred before the end of 2010. The Commission has already determined that the legal costs are appropriate for deferral account treatment by approving the establishment of the deferral account specifically for the purposes of capturing litigation costs in this matter pursuant to Order G-193-08.

The following is an excerpt from Page 4 of the Order:

> *"ROW Encroachment by land developer - ROW Encroachment costs have been presented as a deferred charge. Hold amount in deferral account pending court decision. If court decision is favourable, record recovered cost to the deferral account, then amortize the residual into rates."*

208.3 Please provide the approved and actual O&M costs related to the "maintenance of right of way ("ROW") agreements" in the Operations Support department for 2011, 2012 and 2013.

Response:

The approved and actual O&M for the maintenance of the right of way (ROW) agreements are not separated from 'Property Services' described above.

We have therefore provided the O&M costs related to Property Services for 2011 to 2013 which includes the maintenance of ROW agreements. FBC's 2007 PBR Plan, like the proposed 2014 PBR Plan, did not allocate O&M Expense by department therefore there is not an approved amount for 2011.

See table below.

	2011 Actual	2012 Actual	2012 Approved	2013 Projection	2013 Approved
Property Services O&M	164	170	152	154	154

208.4 Why does the Company not expect to recover these costs from the developer? If the costs are not the responsibility of the developer, why are they the responsibility of the ratepayers?

Response:

Please refer to the response to BCUC IR 1.131.2.1 for an explanation of the litigation.

Although the BC Supreme Court found in favour of FBC and made an award of FBC's legal costs in favour of FBC, the developer appealed the Supreme Court's decision. We have estimated that the amount of legal costs that we could potentially recover from the developer, in accordance with court rules respecting the award of costs, is approximately $10 thousand. Although it may not be possible or cost effective for the Company to recover these costs from the developer, we will continue to assess our ability to collect these legal costs in the future. In the event that we determine that our potential collection costs will be less than the amount of the legal costs that FBC is owed by Hilltop, we will pursue collection and credit the costs to the deferral account. Any of FBC's legal costs that are not recovered from the developer are appropriately the responsibility of the ratepayers, as ordered in Order G-193-08, as FBC's prudence in defending the litigation has benefitted our ratepayers.

208.5 Has FBC demonstrated the prudency of the $120,000 of legal costs?

Response:

Yes. Please refer to the responses to BCUC IRs 1.131.2.1 and 1.208.4.

208.6 Why is this type of activity considered for deferral treatment rather than being an ongoing cost of business within Base O&M?

Response:

Please refer to the responses to BCUC IRs 1.131.2.1 and 1.208.4 for an explanation of the litigation. As FBC states in the Application, the Commission has already approved the deferral and recovery of these costs.

The majority of the costs for this matter were incurred before the end of 2010. FortisBC does not anticipate incurring many more legal costs for this matter unless the developer attempts to pursue its appeal. As a result, we anticipate closing the deferral account by the end of 2014.

209.0 Reference: Exhibit B-1, pp. 271, 285-288

Deferred Debt Issue Costs

Additions to the Deferred Debt Issue Costs deferral account are $1,587 thousand in 2013 and $1,279 thousand in 2014.

209.1 Please provide details for the debt issuances that these costs relate to.

Response:

Deferred Debt Issue Costs	Balance at Jan 1, 2013	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	General Amortization	Balance at Dec. 31, 2013
Series G	78				(7)	71
Series H	41				(13)	28
Series I	128				(14)	114
Series 1 - 04	389				(204)	185
Series 1 - 05	603				(26)	577
Series 1 - 07	701				(20)	681
MTN Series 1 - 2009	664			(59)	(25)	580
MTN Series 2 - 2010	701			(36)	(19)	646
MTN Series 2013	-	1,587	34	(82)	(2)	1,537
	3,305	1,587	34	(177)	(330)	4,419

Deferred Debt Issue Costs	Balance at Jan 1, 2014	Additions and Transfers	Add Deferred Financing Cost	Less Taxes	General Amortization	Balance at Dec. 31, 2014
Series G	71				(7)	64
Series H	28				(13)	15
Series I	114				(14)	100
Series 1 - 04	185				(185)	-
Series 1 - 05	577				(26)	551
Series 1 - 07	681				(20)	661
MTN Series 1 - 2009	580				(24)	556
MTN Series 2 - 2010	646			(35)	(19)	592
MTN Series 2013	1,537			(80)	(51)	1,406
MTN Series 2014	-	1,279		(65)	-	1,214
	4,419	1,279	-	(180)	(359)	5,159

210.0 Reference: Exhibit B-1, pp. 274, Table D4-4

Deferral Accounts

Table D4-4 is a summary of FBC's deferral account requests contained in this Application.

210.1 If the Commission required FBC to limit the number of deferral accounts to only those which 1) are beyond the reasonable control of Utility management, 2) would create significant fluctuations in customer rates of Utility earnings, and 3) are not normally "at risk" items of a competitive business, which deferral accounts would be considered for elimination and what would be the extent of the risk for customers or the Utility?

Response:

As discussed further, the Company is of the opinion that none of its requested deferral accounts should be eliminated or limited as, in aggregate, they are beyond the reasonable control of the Company and/or would otherwise create fluctuations in customer rates or the Company's earnings.

1. Throughout the RRA and the information requests, the Company has explained that many of its deferral accounts arise from events and factors that are beyond the reasonable control of management, such as, but not limited to, Insurance Expense Variance deferral, Interest Expense Variance, Tax Variance, Property Tax Variance, Pension and OPEB expense variance, Harmonized Sales Tax Removal/Provincial Sales Tax Implementation. The balances in these accounts are the result of external markets and changes in regulations. Additionally, the Company cannot reasonably control legislative and Commission directives and decisions that require the creation of deferrals relating to items such as, but not limited to, GCOC Revenue Requirement impact, BCUC GCOC Proceeding costs, City of Kelowna Acquisition Customer Benefit, BCUC Inquiry into the MRS Program, Kettle Valley Expenditure Review, Transmission Customer Rate Design, 2012 Mandatory Reliability Standards Audit and On-Bill Financing Participant Loans.

2. As is commonly done in the rate-regulated industry, deferral accounts are utilized to mitigate fluctuations in customer rates or earnings by attempting to match the costs with the benefits of the deferred items to mitigate inter-generational inequities. Deferral accounts such as, but not limited to, the Rate Stabilization Deferral Mechanism (RSDM), the Pension and OPEB Expense Variance, CPCN Projects Preliminary Engineering, Debt Issue Costs and On-Bill Financing Participant Loans, Trail Office Lease Cost, Trail Office Rental to School District 20, are being used to obtain the matching of costs and benefits and in part being used to smooth out the effect on customer rates.

3. While a non-regulated competitive business may also be at risk for many of the items, it is fundamentally different than a regulated business as it would be able to adjust its sale price, or rates, to ensure recoverability of the cost of its product or service. Whereas a regulated utility's rates are typically set for a test period, a non-regulated competitive business can change its price or rate at the time the input cost changes, as opposed to waiting until a subsequent period. Since the fundamental characteristics of a non-regulated competitive business are so different from a rate-regulated entity such as FBC, this third criterion is not a relevant criterion or test.

It should also be noted that the preamble to the question is specifically referring to Table D4-4 on page 274, Section D4 of the 2014-2018 PBR Application, which lists various requests including the discontinuation or full amortization of 35 deferral accounts by 2014 or 2015. Therefore FBC has in essence already proposed a plan to eliminate many of the deferral accounts in Table D4-4 by 2014 or 2015.

In conclusion, the Company is of the opinion that its deferral accounts serve to benefit the customers and Company by ensuring that only the true costs are paid for and avoids the potential for windfall gains or losses.

210.2 Which deferral accounts would not be allowed under IFRS if FBC were to face similar accounting practices of other competitive Canadian companies?

Response:

IFRS does not recognize rate-regulated accounting; therefore, none of the deferral accounts in Table D4-4 Summary of Deferral Accounts Request, with the exception of debt issue costs, would be expected to be recognized as assets or liabilities under IFRS.

211.0 Reference: Exhibit B-1, pp. 285-288

Deferred Charges and Credits

211.1 Please expand Table 1-B to include the continuity schedule of all deferred charges and credits between December 31, 2011 and December 31, 2012.

Response:

Please refer to the table below.

		Balance at Dec. 31, 2011	Additions and Transfers	Add Deferred Interest	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2012
					($000s)				
	Energy Policy								
1	Demand Side Management	11,417	6,960	-	(1,740)	-	-	(1,771)	14,866
2		**11,417**	**6,960**	**-**	**(1,740)**	**-**	**-**	**(1,771)**	**14,866**
3									
4									
5	**Revenue and Power Supply Variance Deferral Accounts**								
6	Power Purchase Expense Variance Deferral including Water Fees	-	(8,437)	(122)	-	-	-	-	(8,559)
7	Revenue Variance	-	3,377	49	-	-	-	-	3,426
8		**-**	**(5,060)**	**(73)**	**-**	**-**	**-**	**-**	**(5,134)**
9		-							-
10	**Non-Controllable Items Variances**								
11	Property Tax Variance Deferral Account	-	-	-	-	-	-	-	-
12	Interest Expense Variance Deferral Account	-	-	-	-	-	-	-	-
13	Pension & Other Post Retirement Benefits Expense Variance	-	4,155	60	(1,054)	-	-	-	3,161
14	Insurance Expense Variance Deferral Account	-	-	-	-	-	-	-	-
15	Prepaid Pension Costs	6,346	(4,130)	296	1,024	-	(450)	(46)	3,040
16	Other Post Employment Benefits (OPEB)	(9,354)	(7,880)	(1,042)	2,267	-	730	(161)	(15,441)
17	US GAAP Pension Transitional Obligation	-	2,194	61	(564)	(183)	(4)	46	1,550
18	US GAAP OPEB Transitional Obligation	-	5,488	146	(1,408)	(644)	(12)	161	3,730
19	Tax Variance Deferral Account	-	-	-		-	-	-	-
20		**(3,008)**	**(173)**	**(480)**	**265**	**(827)**	**264**	**-**	**(3,959)**
21									
22	**Preliminary and Investigative Charges**								
23	2012 Integrated System Plan	2,559	(2,559)	-		-	-	-	-
24	P1 - P4 Sustainment Capital	6	-	-		(6)	-	-	-
25	Corra Linn Spillway Concrete & Spill Gate Rehab CPCN	-	75	2		-	-	-	78
26		**2,565**	**(2,484)**	**2**	**-**	**(6)**	**-**	**-**	**78**
27	**Regulatory Compliance**								
28	City of Kelowna Acquisition Legal and Regulatory Costs	-	140	4	(36)	-	-	-	109
29	Kettle Valley Expenditure Review	-	70	-	(17)	-	-	-	52
30	BCUC Generic Cost of Capital Proceeding	-	16	0	(4)	-	-	-	13
31	BCUC Inquiry into the Mandatory Reliability Standards (MRS) Program	-	1	0	(0)	-	-	-	0
32	Transmission Customer Rate Design	-	80	2	(21)	-	-	-	62
33		**-**	**307**	**7**	**(79)**	**-**	**-**	**-**	**236**
34									

		Balance at Dec. 31, 2011	Additions and Transfers	Add Deferred Interest	Less Taxes	Amortized / Transferred to Other Accounts	Deferred Interest Amort.	General Amortization	Balance at Dec. 31, 2012
					($000s)				
35	**Other Deferral Accounts**								
36	ROW Reclamation (Pine Beetle Kill)	1,211	-	-	-	-	-	(173)	1,038
37	2012 Integrated System Plan - Engineering	-	2,601	58	(665)	-	(12)	(508)	1,474
38	2014-2018 Capital Expenditure Plan - Engineering	-	259	8	(67)	-		-	200
39	Renewal of BCH Power Purchase Agreement	98	145	8	(38)	-	(5)	(112)	95
40	2012 MRS Audit	-	571	17	(147)	-	-	-	441
41	MRS 2012-2013 Incremental O&M Expense	-	320	10	(83)	-	-	-	248
42	Deferred Debt Issue Costs	3,765		-	(96)	-	-	(364)	3,305
43		**5,073**	**3,896**	**101**	**(1,095)**	**-**	**(17)**	**(1,157)**	**6,801**
44									
45	**Residual Deferral Accounts**								
46	Kelowna Bulk Transformer Capacity Addition	198	108	15		-	-	-	322
47	2010 Flow-Through and ROE Sharing Mechanism Adjustments	(380)	-	-		380	-	-	-
48	2011 Flow-Through and ROE Sharing Mechanism Adjustments	(6,887)	-	-		5,840	-	-	(1,046)
49	2012 Revenue Overcollection	-	(1,941)	(28)		-	-	-	(1,969)
50	2012 Integrated System Plan and 2012-2013 Revenue Requirements	1,080	886	69	(241)	-	(54)	(1,190)	550
51	PST Implementation (HST Removal or Reform Variance)	-	3	-	(1)	-	-	-	2
52	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	309	212	-	(53)	-	-	(86)	382
53	Cost of Service Analysis and Rate Design Application	1,134	50	-	(12)	-	-	(374)	798
54	BC Hydro Waneta Transaction Application	133	-	-		-	-	(66)	66
55	BC Hydro Amendment to 3808 (PPA Proceedings)	27	-	-		-	-	(27)	-
56	2011 Revenue Requirements	55	-	-		-	-	(54)	1
57	Residential Inclining Block Rate & Industrial Stepped Rate Appl.	139	75	-	(19)	-	-	(73)	121
58	Implementation of New Rate Structure	16	-	-	-	-	-	(18)	(2)
59	Irrigation Rate Payer Group Consultation and Load Research	13	41	1	(10)	-	-	-	45
60	Trail Office Lease Costs	143	-	-		-	-	(12)	131
61	Trail Office Rental to SD#20	(786)	-	-		(65)	-	-	(851)
62	Princeton Light and Power Computer Software	17	-	-		-	-	(10)	7
63	Princeton Light and Power Deferred Pension Credit	(35)	-	-		-	-	12	(23)
64	Demand Side Management Study	123	-	-		-	-	(61)	61
65	US Generally Accepted Accounting Principles	523	(65)	-	16	-	-	(297)	178
66	Joint Pole Use Audit 2008	44	-	-		-	-	(22)	22
67	Revenue Protection	161	-	-		-	-	(173)	(12)
68	Right of Way Encroachment Litigation	63	-	5	(2)	-	-	-	67
69	Joint Pole Use Audit 2013	-	-	-		-		-	-
70	Mandatory Reliability Standards Implementation	755	-	53	(15)	-	(12)	(239)	542
71	Shaw Application for Transmission Facility Access	264	(367)	-	103	-	-	-	-
72		**(2,891)**	**(997)**	**116**	**(234)**	**6,156**	**(66)**	**(2,692)**	**(608)**
73									
74	**Grand Total of Deferred Charges:**	**13,156**	**2,448**	**(327)**	**(2,883)**	**5,323**	**181**	**(5,619)**	**12,278**

211.1.1 For any deferral accounts with a variance between the December 31, 2012 balance approved by Order G-110-12 and December 31, 2012 balance provided in Exhibit B-1 (Table 1-B), please provide an explanation to support the variance.

Response:

Deferral Account	Approved	Actual	Variance	Explanation
	($000s)			
Demand Side Management	16,490	14,866	(1,624)	Variance due to program underspend in 2011 and 2012 partially due to step change in budget and ramp-up time necessary to build capacity and launch new programs. See also response to CEC IR 1.7.1.
Power Purchase Expense Variance	-	(8,559)	(8,559)	Savings attributable to a combination of lower loads than forecast and favourable market conditions allowing displacement of forecast purchases under the BC Hydro PPA with market purchases. See also Section C2.2.
Revenue Variance	-	3,426	3,426	Variance in sales revenue attributable to weather related load variances, customer usage rate variances and customer count variances.
Pension & Other Post Employment Benefit (OPEB) Variance	-	3,161	3,161	This deferral account was forecast at zero as it was approved to capture any variance between approved and actual 2012 Pension and OPEB expense. The balance is reflective of the increase in actual Pension and OPEB expense primarily as a result of a decrease in the actuarially determined discount rate.
Prepaid Pension Costs and OPEB Liability	(7,255)	(12,401)	(4,786)	Increase in overall pension and OPEB liability is primarily due to higher actual Pension and OPEB expense related to a decrease in the actuarially determined discount rate, as well as a decrease in Company contributions related to a decrease in pensionable payroll as compared to forecast.
KBTCA Project	286	322	36	Nominal budgetary variance
BCUC Generic Cost of Capital Proceeding	-	13	13	Refer to the response to BCUC IR 1.198.1

Deferral Account	Approved	Actual	Variance	Explanation
	($000s)			
2012 Integrated System Plan - Engineering	2,080	1,474	(606)	Variance due to lower than forecast internal labour and external consultant and legal costs.
2014-18 Capital Expenditure Plan	-	200	200	Refer to the response to BCUC IR 1.197.2
Deferred Debt Issue Costs	3,335	3,305	(30)	Nominal budgetary variance
Section 71 Filing (Waneta Expansion PPA)	86	382	296	Increased expenditures arising from an application for reconsideration of Order E-29-10 filed by the Industrial Customers Group on November 10, 2011.
Cost of Service and Rate Design Application	748	798	50	Nominal budgetary variance
2012-2013 Revenue Requirements Application and Review of 2012 Integrated System Plan	1,244	550	(694)	Variance due to lower than forecast BCUC and Intervener costs related to the oral public hearing to review the application, and to lower than forecast legal and consulting costs.
Irrigation Ratepayer Group Consultation & Load Research	76	45	(31)	Variance due to timing. Installation of metering in 2012 delayed. Project carryover into 2013.
US GAAP	297	178	(119)	Actual costs relating to trust indenture amendment changes and supplementary accounting and consulting services came in less than the approved 2012 forecast which was established in mid-2011.
MRS Implementation	502	542	40	Nominal budgetary variance

Note: All amounts shown in the table are after tax.

211.2 For any 2013 deferral account additions that are based on projected actual 2013 costs, rather than the final actual costs incurred, please discuss how FBC proposes to true-up the projected actual additions to final actual additions during the PBR period.

Response:

Any variances from forecast will be trued up in the following year, as is the usual practice. Actual costs will be recorded in the deferral account as incurred. Amortization will be recorded at the amount approved. The result is that the future balance equals the difference between actual and forecast, and this difference is amortized in the subsequent year. In this manner, total amortization expense will be equal to actual expenditures.

J. PENSION AND OPEB

212.0 Reference: Exhibit B-1, pp. 113, 179, 181, 285

2013 Base – Pension Adjustment

Table C4-2 includes a 2013 Deferral Pension adjustment of $2,158 thousand. Table C5-2 includes a 2013 Pension adjustment of $1,723 thousand for "…increased 2013 pension amounts."

FBC submits that "The difference between the actual and approved 2013 pension and OPEB expense has been accumulated in a deferral account which was approved pursuant to Order G-110-12." (p. 117) Additions to the Pension and Other Post Employment Benefit (OPEB) Variance account in 2013 are $5,272 thousand, less taxes of $1,359 thousand.

212.1 Please confirm that the adjustments of $2,158 thousand and $1,723 thousand to Table C4-2 and Table C5-2, respectively, relate to the variance between forecast and projected 2013 pension expense. If not confirmed, please explain otherwise.

<u>Response:</u>

The pension and OPEB adjustments of $2,158 thousand and $1,723 thousand to the 2013 Base O&M in Table C4-2 and 2013 Base Capital in Table C5-2, respectively, do relate to, but are not representative of the entire variance of $5,272 thousand between the projected and approved 2013 pension and OPEB expense. With $2,158 thousand of the variance allocated as an increase to 2013 Base O&M included in Table C4-2, $1,723 thousand is allocated as an increase to 2013 Base Capital in Table C5-2 and the balance of $1,391 thousand would have been allocated to the Major Projects in Table C5-2 which was excluded from the 2013 Base Capital formula. Please also refer to the reconciliation provided in the response to BCUC IR 1.212.1.1.

212.1.1 Please provide a reconciliation of the Pension adjustments to Table C4-2 and Table C5-2 and the 2013 additions to the Pension and Other Post Employment Benefit (OPEB) Variance account, with an explanation for any reconciling items.

Response:

The requested reconciliation is as follows:

	2013 (in $000s)
Increase in Pension/OPEB expense allocated to:	
2013 Base O&M in Table C4-2	2,158
2013 Base Capital in Table C5-2	1,723
Major Projects excluded from 2013 Base Capital in Table C5-2	1,391
Total 2013 Additions to Pension and OPEB Variance Account (per Table 1-B of Section E)	**5,272**

213.0 Reference: Exhibit B-1, p. 117

Pension and OPEB Capital and O&M Forecasts

Table C4-3: Pension and OPEB Capital and O&M Forecasts ($thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Pension & OPEB expense	12,962	12,299	11,445	10,591	9,870	9,280
Pension & OPEB expense allocated to capital	6,740	6,395	5,951	5,507	5,132	4,825
Pension & OPEB expense allocated to O&M	6,222	5,904	5,494	5,084	4,738	4,454

213.1 Please provide a copy of the 2013 actuarial estimates to support the 2013 pension and OPEB expense forecast from the third party actuary, Towers Watson.

Response:

Please refer to Attachment 213.1 for a copy of the Towers Watson's actuarial projections of financial information for 2013 to 2018, which include the estimates of FBC's pension and OPEB expense for 2013 and 2014.

The reconciliation of the pension and OPEB expense included in the attached Towers Watson projections and FBC's pension and OPEB expense included in Table C4-3 in the preamble to this IR is as follows:

	2013 Base	2014 Forecast
	($000s)	
Per Towers Watson actuarial projection report:		
Pensions net benefit cost	8,923	8,159
OPEBs net benefit cost	3,213	3,314
Subtotal	12,136	11,473
Add amortization of transitional obligations approved pursuant to BCUC Order G-110-12:		
• Amortization of US GAAP Pension Transitional Obligation	183	183
• Amortization of 2005 CICA OPEB Liability	480	480
• Amortization of US GAAP OPEB Transitional Obligation	163	163
Total Pension & OPEB expense included in Table C4-3	**12,962**	**12,299**

213.2 Please provide a copy of the actuarial estimates of the 2014 pension and OPEB expense completed by the third party actuary, Towers Watson.

Response:

Please refer to the response to BCUC IR 1.213.1 which includes Towers Watson's actuarial projections of financial information for 2013 to 2018, including the estimates of FBC's pension and OPEB expense for 2013 and 2014.

213.3 Please discuss how FBC determines the allocation of Pension and OPEB expense forecasts between O&M and capital.

Response:

FortisBC includes its pension and OPEB expenses in its labour loadings, therefore the allocation between O&M and capital, along with other labour loadings, is based on where labour is expected to be charged or allocated. On page 117 of Section C4, in table C4-3, the allocation of pension and OPEB expenses, which follows the expected labour allocation between capital and O&M is approximately 52% and 48%, respectively, for each of 2014 to 2018.

213.4 Please complete the following schedule of pension and OPEB expense and provide the completed schedule in a working excel document.

Pension and OPEB Expense	2009 Approved	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2013 Approved	2013 Projected	2014 Forecast
					($ thousands)					
Pension Expense										
Current Service Cost										
Interest Cost										
Expected Return on Plan Assets										
Amortization of Net Actuarial Loss										
Amortization of Transitional Asset										
Subtotal Pension Expense										
Other Expenses										
Total Pension Expense										
OPEB Expense										
Current Service Cost										
Interest Cost										
Expected Return on Plan Assets										
Amortization of Net Actuarial Loss										
Amortization of Transitional Asset										
Subtotal Pension Expense										
Other Expenses										
Total OPEB Expense										

Response:

Pension and OPEB Expense	2009 Approved	2009 Actual	2010 Approved	2010 Actual	2011 Approved	2011 Actual	2012 Approved	2012 Actual	2013 Approved	2013 Projected	2014 Forecast
			($ thousands)								
Pension Expense											
Current Service Cost	2,707	2,592	2,656	2,656	3,767	3,767	3,811	5,570	3,918	6,094	6,273
Interest Cost	7,198	6,966	7,265	7,265	7,140	7,140	7,835	7,057	8,375	7,244	7,691
Expected Retrun on Plan Assets	(6,730)	(6,730)	(7,023)	(7,023)	(7,527)	(7,527)	(8,558)	(7,958)	(9,557)	(8,411)	(9,338)
Amortization of Net Actuarial Loss	808	808	1,470	1,470	2,646	2,646	1,603	3,969	1,303	3,986	3,612
Amortization of Transitional Asset	891	891	891	891	891	891	-	-	-	-	-
Pension Prior Service Cost	164	164	164	164	164	164	-	62	-	10	(79)
Subtotal Pension Expense	5,038	4,691	5,423	5,423	7,081	7,081	4,691	8,700	4,039	8,923	8,159
Other Pension Expense											
Amortization of US GAAP Pension Transitional Obligation	-	-	-	-	-	-	183	183	183	183	183
Total Pension Expense	**5,038**	**4,691**	**5,423**	**5,423**	**7,081**	**7,081**	**4,874**	**8,883**	**4,222**	**9,106**	**8,342**
OPEB Expense											
Current Service Cost	643	643	886	886	1,065	1,065	1,067	1,415	1,121	1,591	1,655
Interest Cost	926	926	1,104	1,104	1,206	1,206	1,312	1,112	1,408	1,196	1,281
Expected Retrun on Plan Assets	-	-	-	-	-	-	-	-	-	-	-
Amortization of Net Actuarial Loss	90	90	266	266	418	418	347	345	296	426	378
Amortization of Transitional Asset	364	364	364	364	364	364	-	-	-	-	-
Subtotal OPEB Expense	2,023	2,023	2,620	2,620	3,053	3,053	2,726	2,872	2,825	3,213	3,314
Other OPEB Expense											
Amortization of 2005 CICA OPEB Liability	480	480	480	480	480	480	480	480	480	480	480
Amortization of US GAAP OPEB Transitional Obligation	-	-	-	-	-	-	163	163	163	163	163
Total OPEB Expense	**2,503**	**2,503**	**3,100**	**3,100**	**3,533**	**3,533**	**3,369**	**3,515**	**3,468**	**3,856**	**3,957**

Please refer to Attachment 213.4 for the requested schedule in Excel format.

213.4.1 Are all components of the pension and OPEB expense recovered in rates? If not, please list the specific components that are funded by the ratepayer.

Response:

Yes.

213.4.2 If there are any Pension and OPEB costs included in the "Other Expenses" category of the table provided above, please provide a description of the expenses included.

Response:

The table provided in the response to BCUC IR 1.213.4 has replaced the line "other expenses" with the following description of expenses:

- Amortization of US GAAP Pension Transitional Obligation.
- Amortization of 2005 CICA OPEB Liability.
- Amortization of US GAAP OPEB Transitional Obligation.

214.0 Reference: Exhibit B-1, p. 285

Pension and OPEB Expense Variance Deferral Account

"FBC is requesting approval to extend the amortization period of this account from the currently approved 3 year period to the Expected Average Remaining Service Life (EARSL) of the benefit plans. The EARSL amortization period more appropriately allocates the costs over the future period to which they are applicable."

214.1 Please confirm that the 2013 additions to the Pension and OPEB Expense Variance Deferral Account are based on variance between forecast and projected actual, rather than actual, pension and OPEB expense. If not confirmed, please explain otherwise.

Response:

Not confirmed. The 2013 additions of $5.272 million to the Pension and OPEB Expense Variance Deferral Account are representative of the difference between the approved and actual 2013 pension and OPEB expense. The actual 2013 pension and OPEB expense is already known as it is determined by the Company's third party actuary based on the financial position of the pension plans and OPEBs as of January 1, 2013. There is always the potential that pension plan amendments could be made effective during the year which would affect the actual pension and OPEB expense, however this is not a routine occurrence. As such, it is expected that the 2013 pension and OPEB expense used to determine the 2013 addition to the Pension and OPEB Expense Variance Deferral Account is actual in nature, rather than forecast or projected.

214.1.1 If the preceding IR is confirmed, please discuss why in FBC's opinion it is appropriate to include additions to this deferral account even though the actual 2013 pension and OPEB expense is currently unknown.

Response:

Please refer to the response to BCUC IR 1.214.1 which indicated "not confirmed" as the actual 2013 pension and OPEB expense is currently known based on the January 1, 2013 measurement date.

214.2 Please elaborate of why FBC considers the EARSL to be the appropriate amortization period for the variance between forecast and actual pension and OPEB expense.

Response:

FBC considers the EARSL to be the appropriate amortization period of the 2012 and 2013 pension and OPEB expense variance for several reasons.

Firstly, as discussed in Section D4.2.4 on page 265 of the Application, extending the amortization period to the EARSL more appropriately allocates the costs over the future period to which they are applicable. The EARSL is an average of the employees' average expected time to retirement and would represent the period of time FBC would expect the employee, on average to be an employee. Employee future benefits accounting results in actuarial gains and losses which require amortization into the pension/OPEB net benefit cost. The most acceptable method of amortizing actuarial gains/losses is over the EARSL. There is no set method under accounting guidance to amortize deferral accounts, such as the variance between forecast and actual pension and OPEB expense. However, by their nature, the pension and OPEB variance is very similar to actuarial losses and therefore FBC believes that this amortization term is appropriately supportable and comparable.

Secondly, as the nature of these costs is uncontrollable, large fluctuations in this account can occur from year to year. A longer amortization period allows for smoother rates for customers in future years that follow a year with high volatility in pension and OPEB costs. As a result, EARSL allows for the fluctuations in the costs to be captured and spread out over the average time the employees are expected to be an active employee of FBC.

Finally, the use of EARSL to account for pension/OPEB expense has previously been accepted and approved by the BCUC when FBC began amortizing the accumulated Canadian GAAP 2005 OPEB liability over the EARSL pursuant to Commission Order G-52-05 and when FBC began amortizing the US GAAP pension and OPEB transitional obligations over the EARSL beginning in 2012 pursuant to Commission Order G-110-12.

214.2.1 Please discuss the purpose of the EARSL in pension accounting.

Response:

Please refer to the response to BCUC IR 1.214.2.

215.0 Reference: Exhibit B-1, pp. 260, 287, 300

Prepaid Pension Costs and OPEB Liability Deferral Account

"…FBC is proposing 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." (p. 246)

215.1 Please discuss why FBC has decided to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014.

Response:

FBC has proposed to discontinue the net-of-tax treatment for pension and OPEB funding differences effective for 2014 for several reasons.

First, on page 242 of Section D2: Taxes under item 2.4.2 Discontinuation of Net of Tax Treatment for Pension and OPEBs, FBC stated that "the Prepaid Pension and OPEB liability deferral accounts are not amortized into rates in a manner like other deferral accounts subject to net of tax treatment pursuant to BCUC Order G-52-05 whereby both the deferral balance and the tax effect are amortized into rates. 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."

Second, as stated on pages 242 and 243 of Section D2: Taxes under item 2.4.2 Discontinuation of Net of Tax Treatment for Pension and OPEBs "discontinuing the net of tax recognition on these employee future benefit deferral accounts would be consistent with the treatment approved by the BCUC pursuant to G-141-09 for FEI." Accordingly, the Commission has previously accepted and approved the discontinuation of net of tax treatment for Pension and OPEB funding differences.

Third, as described in the responses to BCUC IRs 1.215.3 and 1.215.4, the net of tax treatment applied to pension and OPEB funding differences is not even a common practice within the rate-regulated utility industry.

When considering the above points, the appropriate principle when accounting for pension and OPEB funding differences is to not apply a net of tax treatment.

215.2 Please recreate 1) "Schedule 3 – Income Tax Expense" and 2) Line No. 12 of "Table 1-B – Deferred Charges and Credits (2014)" using the net-of-tax treatment for the pension and OPEB funding differences approved for 2013 and years prior to 2013.

Response:

Note that the net of tax treatment change is effective January 1, 2014, therefore the actual 2012 and forecast 2013 tax expense in the requested recreation of Schedule 3 and the pension and OPEB balances in the deferred charges schedule to the end of 2013 are already subject to the net of tax treatment prior to 2014 and are unchanged from what was filed in the 2014-2018 PBR RRA.

1) The recreation of Schedule 3 – Income Tax Expense using the net-of-tax treatment for the pension and OPEB funding differences approved for 2013 and years prior to 2013 is as follows:

SCHEDULE 3 - INCOME TAX EXPENSE
Using net-of-tax treatment for Pension & OPEB

		Actual 2012	Forecast 2013	Forecast 2014
				($000s)
1	UTILITY INCOME BEFORE TAX	96,293	97,507	96,692
2	Deduct:			
3	Interest Expense	38,686	39,848	42,608
4				
5	ACCOUNTING INCOME	57,607	57,659	54,085
6				
7	Deductions			
8	Capital Cost Allowance	58,308	60,302	67,932
9	Capitalized Overhead	10,969	11,524	12,277
10				
11	Incentive & Revenue Deferrals	(781)	(6,159)	(8,360)
12	Financing Fees	338	655	707
13	Pension Contribution	-	-	-
14	Other Post Employment Benefit (OPEB) Contribution	-	-	-
15	All Other (net effect)	463	365	58
16		69,297	66,687	72,614
17				
18	Additions			
19	Amortization of Deferred Charges	5,439	5,520	6,887
20	Pension Expenses	-	-	-
21	Other Post Employment Benefit (OPEB) Expenses	-	-	-
22	Depreciation	43,149	44,261	50,886
23		48,588	49,781	57,773
24				
25	TAXABLE INCOME	36,898	40,753	39,243
26				
27	Tax Rate	25.00%	25.00%	25.0%
28				
29	Tax Payable	9,224	10,188	9,811
30	Prior Years' Overprovisions/(Underprovisions)	(167)	-	(805)
31	Investment Tax Credit	(18)	-	-
32	PensionTax Effect	-		-
33	Deferred Charges Tax Effect	58	175	180
34				
35	**REGULATORY TAX PROVISION**	**9,097**	**10,363**	**9,186**

2) The recreation of line No. 12 of "Table 1-B - Deferred Charges and Credits (2014)" using the net-of-tax treatment for the pension and OPEB funding differences approved for 2013 and years prior to 2013 is as follows:

		Balance at Dec 31, 2013	Additions and Transfer	Less Taxes	Balance at Dec 31, 2014
12	Prepaid Pension Costs and OPEB Liability	(16,858)	(166)	42	(16,983)

215.2.1 Please confirm the forecast 2014 cost of service impact of switching from the net-of-tax treatment for the pension and OPEB funding differences to the treatment proposed in the PBR Application.

Response:

The forecasted 2014 cost of service impact of switching from the net of tax treatment for pension and OPEB funding differences to the treatment included in the 2014 income tax expense forecast in the PBR application is an increase of approximately $55 thousand. Stated another way, if the net of tax treatment was still applied to pension and OPEB funding differences, the 2014 income tax expense in the PBR Application would decrease approximately $55 thousand from $9,241 thousand to $9,186 thousand.

215.3 Please provide examples of other Canadian regulated utilities that use the tax treatment proposed by FBC in the PBR Application for accounting for the pension and OPEB funding differences.

Response:

AltaGas, AltaLink, Enbridge Gas, FortisAlberta, Newfoundland Power, FortisBC Energy and Union Gas, all Canadian regulated utilities who pay corporate income tax, do not use the net of tax treatment for accounting for pension and OPEB funding differences, consistent with what is proposed by FortisBC in the 2014-18 PBR Application.

215.4 Please provide examples of other Canadian regulated utilities that use the net-of- tax treatment for accounting for the pension and OPEB funding differences.

Response:

The only other Canadian regulated utility that appears to use the net of tax treatment for accounting for the pension and OPEB funding differences is Pacific Northern Gas who is also regulated by the BCUC.

216.0 Reference: Exhibit B-1, p. 243

Prepaid Pension Costs and OPEB Liability Deferral Account

"FBC records the difference between amounts funded by ratepayers for pensions and OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis."

216.1 Is the amount recorded in the Prepaid Pension and OPEB Liability deferral account the difference between amounts actually paid out by the Company and actual amounts funded by the ratepayers or *forecast* amounts funded by the ratepayers? Please discuss.

Response:

For 2013, the amount recorded in the Prepaid Pension and OPEB Liability deferral account is the difference between the forecasted funding contributions and the actual pension and OPEB expense. 2013 actual funding contributions made by FortisBC will not be determined as actual until the end of 2013. The forecasted contributions are based on estimates provided by the Company's third party external actuary. These estimates of the forecasted contributions are based on the contribution rates set out under the last funding valuation, performed by the defined benefit pension plans' independent actuary, and are required to be made by the Company pursuant to the British Columbia Pension Benefits Standards Act. As discussed in the response BCUC IR 1.214.1, 2013 pension and OPEB expense has already been established as actual and has been determined by the Company's third party external actuary.

While this balance is recognized on the Company's deferred charge schedule, these pension and OPEB funding differences exist for all companies that have defined benefit arrangements, whether they are rate-regulated or not. Further, the recognition of the Prepaid Pension Costs and OPEB Liability Deferral Account has been previously approved by the BCUC and are required as a result of offering employee defined benefit pensions and OPEBs.

"The existing net-of-tax balances of the pension and OPEB will be carried forward as a starting point for 2014, but future additions to **both accounts** will be on a pre-tax basis with the timing of tax deductions recognized in the calculation of income tax expense." [Emphasis added]

216.2 Please name the two deferral accounts that are referenced in the aforementioned quote as "both accounts".

Response:

The two deferral accounts referenced are the Prepaid Pension Cost deferral account and the OPEB liability deferral account which were shown separately in FortisBC's previous RRAs and Annual Reports. These two accounts are now aggregated as one single deferral account as Prepaid Pension Costs and OPEB Liability as per line 14, on page 285 of Section E: Financial Schedules.

> "FBC requests approval to **expand** the prepaid pension and OPEB liability deferral account to also include pension funding differences, and include the additions to this account in rate base on a pre-tax basis." [Emphasis added]

216.3 How does the 'expand[ed]' treatment differ from the existing, approved treatment of the Prepaid Pension Costs and OPEB Liability deferral account? Please discuss.

Response:

FBC is not requesting approval to expand or change the Prepaid Pension Cost and OPEB Liability Deferral, with the exception of discontinuing the net of tax treatment, and this account should only include the pension and OPEB funding differences along with the historical pre-2014 tax effect balances. A revision to this wording on page 243 of the Application is included in Errata No. 2.

> "…discontinuing the net of tax recognition on these employee future benefit deferral accounts would be consistent with the treatment approved by the BCUC pursuant to G-141-09 for FEI."

216.4 Please identify if the approval referenced in the preamble to this IR was granted as part of an oral hearing, written hearing or NSP.

Response:

The approval was granted as part of a NSP.

217.0 Reference: Exhibit B-1, p. 265

Pension and OPEB expense variation

FBC states that: "In this Application, FBC is requesting approval to extend the amortization period of this account from the currently approved 3 year period to the Expected Average Remaining Service Life (EARSL) of the benefit plans."

217.1 If the Commission were to authorize an 11 year amortization of these costs, would that mask the large cost of these ratepayer funded programs? Is there a concern that these deferrals would understate the various O&M cost statistics and therefore optimize FBC's performance? Please discuss.

Response:

The authorization of an 11 year amortization term for the pension and OPEB expense variance would not mask these costs as they would be transparent by being individually categorized in their own deferral account. If the IR is concerned with the principle that customers will repay the variance over a longer period of time than originally requested, FBC believes that using the 11 year amortization outweighs that principle as it achieves a smoothing of customer rates and can be compared against a generally accepted actuarial period term (EARSL) as explained in the response to BCUC IR 1.214.2.

This deferral would not understate the various O&M cost statistics as it was never intended to be collected from customers through the O&M cost of service line item, but rather the amortization of deferred charges cost of service line item. The collection of the pension and OPEB through the amortization and not O&M would occur regardless of whether the original 3 year term which was originally approved pursuant to BCUC Order G-110-12, or the more appropriate term of 11 years is used. Further 2013 Base O&M includes an increase in pension and OPEBs which is reflective of more recent forecasts of pension and OPEB expenses. Therefore customers will be paying for these more recent forecasts of increased pensions and OPEBs on a prospective basis and it will be reflected in O&M. Finally, the 2012-2013 pension and OPEB variance primarily arose as a result of the completely uncontrollable change in the interest rates for long Canada bonds from forecast and therefore should not be considered in any way as part of assessing FortisBC's performance.

K. LABOUR INFLATION AND BENEFITS

218.0 Reference: Exhibit B-1, p. 115; Exhibit B-1-1, Appendix C3

Executive Employees – Pensionable Earnings

"FortisBC's current pension practice of including incentive pay as pensionable, mirrors the treatment of incentive earnings in pensions, practiced by the majority of companies in FortisBC's peer reference group and more specifically is the practice in the regulated utility industry." (p. 115)

The following is an excerpt from the BCUC Decision in the matter of the Pacific Northern Gas Inc. 2012 RRA (Order G-130-12): "The Commission notes that ratepayers should only pay for those costs that are related to the nature and quality of service provided by PNG. Given that PNG does not have a formal document for the 2012 PNG executive incentive/bonus plan and the corporate performance goals are not directly linked to providing future benefits to customers, the Commission is not persuaded that the entire cost of including bonuses in the pensionable earnings of PNG's executives should be recovered from customers. (Exhibit B-10, BCUC 2.120.1) In keeping with previous Commission decisions, the Panel approves the inclusion of only one-third of the executive bonuses in pensionable earnings."

218.1 Please provide the forecast and actual 2012 and the forecast and projected 2013 pension expense related to executive incentive pay.

<u>Response:</u>

Since the executive pension expense includes the current service cost as well as the interest cost on the historical cumulative carry-forward balance of both executive regular and incentive pay, there is a certain degree of estimation required to isolate the component of executive pension expense relating solely to executive incentive pay for 2012 and 2013.

The forecasted and actual 2012 portion of executive pension expense relating to incentive pay was approximately $160 thousand. The forecasted 2013 portion of executive pension expense relating to incentive pay was approximately $155 thousand, while the actual 2013 portion of executive pension expense relating to incentive pay was approximately $165 thousand.

Note that all the executive pension expense, based on both base pay and incentive pay, has been included in the general benefits loading which are allocated, along with other pension plan expenses and benefits, to all FBC employees.

218.2 Does FBC include the full amount of executive short term incentive pay and long term incentive pay in pensionable earnings? If not, please identify the specific types of incentive pay that are included in pensionable earnings.

Response:

FBC includes the full amount of executive short term incentive pay in pensionable earnings. Long term incentive pay is not included in pensionable earnings.

218.2.1 For those portions of executive incentive pay that are funded by the shareholder (i.e. stock options and PSUs), please discuss why, in FBC's opinion, the pension expense related to these amounts should be recovered from the ratepayer.

Response:

The ratepayer is not paying for pension expense related to stock options and PSUs as the executive pension expense is not calculated on stock options and PSUs which are funded by the shareholder.

218.3 Please identify the companies in FBC's peer reference group in Appendix C3 that are regulated utilities.

Response:

The companies in FBC's peer reference group in Appendix C3 that have some regulated utility operations are:

- ATCO Group
- BC Hydro
- Capital Power
- Enbridge Gas Distribution
- ENMAX

- EPCOR
- FortisAlberta
- Insurance Corporation of BC
- Manitoba Hydro
- Spectra Energy
- TELUS
- Trans Alta
- TransCanada PipeLine

Note that each of these companies may not be entirely regulated, but may operate regulated and non-regulated businesses.

218.3.1 For regulated utilities in FBC's peer reference group only, please provide the percentage of companies that include the entire incentive pay in pensionable earnings and the percentage of companies that do not include the entire incentive pay in pensionable earnings.

Response:

This response addresses BCUC IRs 1.218.3.1, 1.218.3.2 and 1.218.3.3.

FBC has conducted an informal survey of the gas and electric utilities listed in response to BCUC IR 1.218.3 whose operations FortisBC considers to be similar to its own. These companies included ATCO, BC Hydro, Enbridge Gas Distribution, FortisAlberta and Manitoba Hydro. Of these companies, only one did not have an incentive pay program. For the remaining four companies, three of them included incentive pay in pensionable earnings, although most had limits on how much is included. Of these three, all of them also recovered the pension expense from ratepayers.

218.3.2 For regulated utilities in FBC's peer reference group only, please list the companies that are eligible to recover the full pension expense related to incentive pay from ratepayers.

Response:

Please refer to the response to BCUC IR 1.218.3.1.

218.3.3 For regulated utilities in FBC's peer reference group only, please list the companies that are not eligible to recover the full pension expense related to incentive pay from ratepayers.

Response:

Please refer to the response to BCUC IR 1.218.3.1.

218.4 Please comment on the 2012 Commission Decision regarding the PNG 2012 RRA, whereby the Commission disallowed 2/3 of executive bonuses in pensionable earnings.

Response:

FBC's use of performance goals differs significantly than that of PNG, as described in the preamble. While "the corporate performance goals are not directly linked to providing future benefits to customers" at PNG, please refer to FBC's response to BCUC IR 1.221.5.1 for a description of how each of FBC's annual corporate objectives are directly linked to customer interests.

It is not clear from the preamble whether "bonuses" refers to short term incentive pay at PNG, long term incentive pay, or both. This may be another point of distinction in that only short term incentive pay for executives at FBC is included in pensionable earnings; long term incentive pay is not.

FBC believes its compensation program for executives is appropriate, prudent and competitive at the market-median. Because the compensation program includes short term incentive pay which is in part dependent on attaining corporate objectives, and because the corporate objectives are designed to provide a direct benefit to the customer, FBC believes that continuing to allow the recovery of short term incentive pay as pensionable earnings is appropriate.

219.0 Reference: Exhibit B-1, p. 114; Exhibit A2-4, FHI Statement of Executive Compensation

Executive Employees – Comparable Organizations

In FBC's 2012-2013 RRA and ISP Application, Exhibit B-4 BCUC IR 1.34.2, page 57, FBC noted that BCUC IR1 Appendix 34.2, Attachment A provides a list of 295 companies in the Commercial Industrial Comparator Group. Included in this reference group were companies such as Barrick Gold Corporation, Rogers Communication Inc., and Suncor Energy Inc.

On page 2 of Form 51-102F6 – Statement of Executive Compensation, For the Year Ended December 31, 2012 FortisBC Holdings Inc., it states: "The Corporation has a policy of compensating executive officers at approximately the median (50th percentile) of comparable Canadian commercial industrial companies. For clarity, this reference group does not include organizations in the financial service and broader public sectors. It includes organizations from the energy, mining and manufacturing sectors." (Exhibit A2-4 FHI Statement of Executive Compensation)

On page 4 of Form 51-102F6 – Statement of Executive Compensation, For the Year Ended December 31, 2012 FortisBC Holdings Inc., it states: "As part of the annual review process, Fortis engages Hay Group Limited ("Hay Group"), its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian Commercial Industrial companies." (Exhibit A2-4 FHI Statement of Executive Compensation)

219.1 Please list the companies that were included in the Comparable Canadian Commercial Industrial reference group produced by Hay Group Limited for each of the last three years.

<u>**Response:**</u>

Please refer to Attachment 219.1 for a list of the companies that were included in the Comparable Canadian Commercial Industrial reference group produced by the Hay Group for each of the last three years.

219.1.1 Please elaborate in detail on how these reference group companies are appropriate comparators for FBC.

Response:

The Hay Group Canadian Commercial Industrial Market, FBC's peer reference group, consists of all publicly traded and privately owned companies in Canada that participate in Hay Group's compensation database, excluding financial organizations. This comparator group represents a broad spectrum of Canadian commercial and industrial organizations with which FBC competes for executive talent. The peer group represents a cross-section of the Canadian economy, as disclosed in Attachment 219.1, provided in the response to BCUC IR 1.219.1.

Generally speaking, the larger the comparator group used the more stable the data year over year. In smaller comparator groups there can be volatility in the data when participants change year over year. As well, in using a broad comparator group, the intent is not for each company in the group to be directly comparable to FBC, but that the group as a whole reflects compensation policy in the Canadian market. By targeting the median within this broad group, FBC ensures its compensation is reflective of market practices.

In addition, a broad based comparator group is selected as FBC has attracted some of its executives from other sectors, and not solely gas or electric utilities.. As well, certain of the current executive team have been recruited from across Canada, which also speaks to the appropriateness of using a national rather than regional comparator group.

While individually organizations in the commercial industrial database have specific executive pay policy and practice, together these organizations represent a stable, national comparator upon which to base compensation policy. FBC maintains good governance on executive compensation decisions and peer groups are an important reference for helping ground executive pay decisions as well as evaluate the link between pay and performance. FBC maintains appropriate comparators as a tool for making responsible market based pay decisions that support the Company's business strategy. This helps to ensure executive pay is set appropriately and reflects a prudent expenditure by FBC.

219.2 Where does FBC rank against comparators in the reference group for indicators such as number of employees, total revenues, and revenue stability (measured in annual revenue change)?

Response:

The Hay Group does not typically rank the participants in the comparator group in terms of number of employees or total revenues. As described in response to BCUC IR 1.219.1.1, some of the value in using a broad-based comparator group comes from having stable, consistent data year over year which is reflective of the Canadian market as a whole.

The Hay Group has confirmed that FBC ranks in the 75th percentile of the comparator group with respect to number of employees and total revenues. Given this relative position within the comparator group, argument for positioning the compensation policy at the 75th could be made. FBC, however, continues to position is compensation policy at the 50th percentile.

219.2.1 Does FBC or its compensation consultant size adjust the market data to account for differences in company revenue, number of employees, or revenue stability? If yes please provide this data. If no, please indicate how much time and effort it would take to complete this task.

Response:

The Hay Group, FBC's primary compensation consultant, provides the following response.

The Hay Group does not size adjust market data based on regression on company revenue, number of employees or revenue stability. In addition, Hay Group is not able to complete this task without fundamentally changing the basis of its analysis.

It should be noted, however, that all positions in the Hay Group database have been evaluated using the Hay Group Guide Chart - Profile Method$_{SM}$ of job evaluation. Each FBC executive role is benchmarked against roles of similar size, in terms of Hay Points, in the comparator market from Hay Group's database.

The Hay Point methodology considers all aspects of the job and the organization. This would include complexity/sophistication of the industry, diversity of products and markets, ownership, market maturity/growth, as well as total revenues, revenue stability, assets and number of employees. Accordingly, market compensation data provided to FBC in its current form (i.e., based on Hay Points) has already considered size and is reflective of all the above factors.

219.3 Why does FBC exclude the broader public sector, the not-for-profit sector, and the financial sector from the executive compensation reference group?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why FBC believes the current reference group companies are appropriate comparators. Some subsets of the Canadian marketplace (such as financial services and the public sector) are excluded from the comparator group because they generally compete for different pools of talent than FBC, and/or because their pay practices are not relevant to FBC.

219.4 Why does FBC include energy, mining and manufacturing firms in the executive compensation reference group?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a summary of why FBC believes the current reference group companies are appropriate comparators.

219.5 Why is Barrick Gold Corporation an appropriate comparator for FBC?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why the reference group companies are appropriate comparators for FBC, and why it is preferable to participate in a broad-based comparator group, rather than directly compare to a single entity such as Barrick Gold Corporation.

219.5.1 How is Barrick Gold Corporation an appropriate comparator considering its total revenue, and exploration and production levels?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why the reference group companies, including Barrick Gold Corporation are appropriate comparators for FBC.

219.6 Why is Suncor Energy an appropriate comparator for FBC?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why FBC believes the reference group companies are appropriate comparators, and why it is preferable to participate in a broad-based comparator group, rather than directly compare to a single entity such as Suncor Energy.

219.6.1 How is Suncor Energy an appropriate comparator considering its total revenue and revenue stability?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why the reference group companies, including Suncor Energy Inc. are appropriate comparators for FBC.

219.7 Why is Rogers Communications an appropriate comparator for FBC?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why FBC believes the reference group companies are appropriate comparators for FBC, and why it is preferable to participate in a broad-based comparator group, rather than directly compare to a single entity such as Rogers Communications.

219.7.1 How is Rogers Communications an appropriate comparator considering the number of employees?

Response:

Please refer to response to BCUC IR 1.219.1.1 for a description of why the reference group companies, including Rogers Communications are appropriate comparators for FBC.

219.8 Please create a list of companies that are comparable to FBC (measured by annual revenue) using the Commercial Industrial Comparator Group. (May refer to either Hay Group, Towers Watson, or other database to perform this task).

Response:

Please refer to Attachment 219.8 for a list of companies, prepared by the Hay Group, that are comparable to FBC (measured by annual revenue) using the Commercial Industrial Comparator Group.

219.8.1 Please add to this list any Canadian organizations that generate, transmit, control and distribute electric power and/or natural gas. Please include both Canadian investor owned firms as well as public sector organizations.

Response:

Please refer to the table below where FBC has summarized Canadian electric and natural gas companies, along with their annual revenue. FBC did not include approximately 70 electric small utilities in Ontario, and some other smaller utilities in other provinces.

Province	Company name	Electric/Gas	Type	Revenue (Million)	Year
British Columbia	BC Hydro	Electric	Public	$4,900	2012/ 2013

Province	Company name	Electric/Gas	Type	Revenue (Million)	Year
	Pacific Northern Gas	Natural gas	Investor	$41	2012
Alberta	ATCO Electric/Gas	Electric/Gas	Investor	$1,842	2012
	EPCOR Utilities	Electric	City of Edmonton	$1,931	2012
	ENMAX Power Corp	Electric	City of Calgary	$3,164	2012
	AltaLink	Electric	Investor	$407	2012
	FortisAlberta	Electric	Investor	$397	2012
	AltaGas Utilities	Natural gas	Investor	$74	2012
	TransCanada	Natural gas	Investor	$4,264	2012
	Medicine Hat	Electric/Gas	City	$301	2012
Saskatchewan	SaskPower	Electric	Public	$1,800	2012
	Saskatoon Light &Power	Electric	City	$18	2012
	SaskEnergy	Gas	Public	$798	2012
Manitoba	Manitoba Hydro	Electric/Gas	Public	$2,062	2012/13
Ontario	Enbridge Gas Distribution	Gas	Investor	$2,574	2011
	Union Gas	Gas	Investor	$1,700	2012
	Brantford Power Inc.	electric	Independent	$24	2012
	Burlington Hydro Inc.	Electric	City	$193	2012
	Centre Wellington Hydro Ltd	Electric	City	$29	2012
	Greater Sudbury Hydro	Electric	City	$123	2012
	Hydro One	Electric	Public	$5,728	2012
	London Hydro Inc.	Electric	City	$441	2012
	Toronto Hydro Electric	Electric	City	$692	2012
New Brunswick	New Brunswick Power	Electric	Public	$1,697	2013
	New Brunswick Operator	Ind. Electric	Public	$82	2012
Quebec	Quebec Hydro	Electric	Public	$2,700	2012
	Gaz Metro	Gas	Investor	$1,365	2012
	Nova Scotia Power (Emera)	Electric	Investor	$1,233	2011
Newfoundland	Newfoundland Power	Electric	Investor	$1,568	2011
	Newfoundland and Labrador Hydro	Electric	Public	$726	2012
Prince Edward Island	Maritime Electric	Electric	Investor	$173	2012
Northern Territories	Northwest Territories Power Corporation	Electric	Public	$83	2012
Yukon	Yukon Energy Corporation	Electric	Public	$33	2010

Province	Company name	Electric/Gas	Type	Revenue (Million)	Year
Nunavut	Qulliq Energy Corporation	Electric	Public	$113	2012

219.8.2 Please add to the list any Canadian non-profit organizations that are comparable to FBC based on the number of employees.

Response:

FBC is unfamiliar with the non-profit sector and is unable to provide this information. Please refer to BCUC IR 1.219.1.1 for a description of why FBC believes its current comparator group is appropriate.

219.9 Please create a list of companies that are comparable to all of FBC/FEI (measured by annual revenue) using the Commercial Industrial Comparator Group. (May refer to either Hay Group, Towers Watson, or other database to perform this task).

Response:

Please refer to Attachment 219.9 for a list of companies, prepared by the Hay Group, that are comparable to all of FBC/FEI (measured by annual revenue) using the Commercial Industrial Comparator Group.

219.9.1 Please add to this list any Canadian organizations that generate, transmit, control and distribute electric power and/or natural gas. Please include both Canadian investor owned firms as well as public sector organizations.

Response:

Please refer to the response to BCUC IR 1.219.8.1.

219.9.2 Please add to the list any Canadian non-profit organizations that are comparable to FBC/FEI based on the number of employees.

Response:

FBC is unfamiliar with the non-profit sector and is unable to provide this information. Please refer to BCUC IR 1.219.1.1 for a description of why FBC believes its current comparator group is appropriate.

220.0 Reference: Exhibit B-1, p. 114, Exhibit A2-4, FHI Statement of Executive Compensation;

Exhibit A2-5 Ontario Ministry of Energy Agency Review;

Exhibit A2-6 Ottawa Hydro;

Exhibit A2-7 Hydro Annual Information;

Exhibit A2-8 NS Power Management Circular 2013;

Exhibit A2-9 StatCan Employment by Class of Worker

Executive Employees – Compensation Studies

On page 114 of the Application (Exhibit B-1) FBC states: “the Company compensates executives at a level generally equivalent to the median of practice among a broad reference group of Canadian commercial industrial companies.”

On page 4 of Form 51-102F6 – Statement of Executive Compensation, For the Year Ended December 31, 2012 FortisBC Holdings Inc., it states: “As part of the annual review process, Fortis engages Hay Group Limited (“Hay Group”), its primary compensation consultant, to provide comparative analyses of market compensation data reflecting the pay levels and practices of Canadian Commercial Industrial companies. Using this data, a detailed review is prepared to analyze the Corporation’s competitive compensation positioning against its peer group. Hay Group provides Fortis and its subsidiaries preliminary recommendations to management on the basis of pay competitiveness, emerging market trends and best practices. In addition, the Corporation may from time to time engage Hay Group to provide specific analysis of its executive compensation components.” (Exhibit A2-4 FHI Statement of Executive Compensation)

On page 5 of Form 51-102F6 it states: “The Corporation also engages Towers Watson and Mercer (Canada) Limited to consult on certain pension and benefit components and to perform certain administrative and actuarial functions related to the Corporation’s pension programs.” (Exhibit A2-4 FHI Statement of Executive Compensation)

A 2007 Report by the Ontario Ministry of Energy entitled “The Report of the Agency Review Panel on Phase 1 of its Review of Ontario’s Provincially-Owned Electricity Agencies” which dealt with executive compensation at provincial electricity institutions recommended on page 19 that “If reference is made to comparator groups: (1) Have careful regard for appropriate comparator organizations in the public and private sectors of similar size, scope and complexity. (2) Provide a 50/50 weighting of such private and public sector organizations in the determination of Total Direct Compensation and Total Compensation.“ (Exhibit A2-5 Ontario Ministry of Energy Agency Review)

On page 73 of Ottawa Hydro's 2011 Annual Report, Ottawa Hydro States: "Executive compensation is reviewed on an annual basis and compared to market data, with the assistance of independent consultants, every two to three years to ensure competitiveness. In line with best practices for the sector, as identified by the Ontario Minister of Energy's Agency Review Panel in 2007, Hydro Ottawa applies a 50/50 weighting of market data from public and private comparators. The industry component of the market comparator group has a strong sector affiliation (e.g. Transportation and Utilities sector), and is assessed by revenue levels to ensure comparability." (See Exhibit A2-6 Ottawa Hydro)

On page 2 of a Toronto Hydro's 2012 annual information form, Toronto Hydro States: "The CEO's compensation is recommended by the Board's Compensation Committee. The Committee also reviews the CEO's proposals for NEO (Named Executive Officers) compensation. Industry comparables (50th percentile) are considered for the purpose of benchmarking the CEO's compensation. In 2012 the selected comparables included: AltaGas Ltd, ATCO Ltd, BC Hydro, Capital Power Corp., Emera Inc., Enbridge Inc., ENMAX Corp., Epcor Utilities, Hydro One, IESO, OEB, Ontario Power Authority, Ontario Power Generation, SaskPower, TransAlta Corp. and Union Gas. (See Exhibit A2-7 Hydro Annual Information)

Nova Scotia Power's 2013 Management Information Circular noted that: "In 2012 the Government of Nova Scotia passed legislation to remove incentive payments from rate base going forward and cap executive salary amounts than can be charged to ratepayers at 110% of the salary of a senior deputy minister for the President and CEO, and 100% of the pay of the salary of a senior deputy minister for other members of the NS Power executive. This change takes effect in 2013." (See Exhibit A2-8 NS Power Management Circular 2013)

Statistics Canada annual labour force survey estimates (LFS), employment by class of worker, North American Industry Classification System (NAICS) Table 282-0012 estimates that 17.5 million Canadian were employed in 2012. The labour force survey estimates that of these 17.5 million Canadians employed in 2012, 3.6 million were employed in the public sector, 11.2 million were employed in the private sector, and 2.4 million were self-employed in 2012. (Exhibit A2-9 StatCan Employment by Class of Worker)

220.1 Please produce any Hay Group Limited reports related to FBC's executive compensation program produced within the last five years. Please ensure that the Hay Group Reports contain values for both Target Compensation and Actual Compensation for each of the components of compensation.

Response:

Please refer to CONFIDENTIAL Attachment 220.1 for the Hay Group reports related to FBC's executive compensation program produced within the last five years. CONFIDENTIAL Attachment 220.1 includes annual salary policy letters in addition to a triennial review summary memo, AND is being filed confidentially as it contains personal compensation information for non-FBC executives (some of which has not previously been publicly released). In addition, it contains information proprietary to the Hay Group.

220.2 Please produce any reports from Towers Watson or Mercer (Canada) Limited, or any other compensation consultant related to FBC's executive compensation program within the last five years.

Response:

In 2011, FBC engaged Towers Watson to conduct a review of the competitiveness of the Company's pension and benefit programs, including vacation, holidays and other paid time off. Please refer to the response to BCUC IR 1.221.2.1, Attachment 221.2.1 for a copy of this review.

No other reports related to FBC's executive compensation program have been produced by compensation consultants within the last five years.

220.3 What is FBC's view regarding the merits of using public sector organizations as part of the reference group for benchmarking executive compensation considering that Statistics Canada estimates that 3.6 million out of a total of 17.5 million employed Canadians work in the public sector?

Response:

Please refer to response to BCUC IR 219.3 for a description of why public sector organizations are excluded from the comparator group FBC participates in, and response to BCUC IR 1.219.1.1 for a description of why FBC believes its current comparator group is appropriate.

It should be noted in the preamble that the StatsCan data reflects all classes of employees, which suggests that a minority of the employees working in Canada (approximately 20%) work in the public sector. In FBC's view, this supports FBC's approach to focus on the private sector for executive compensation matters.

220.3.1 By excluding the government and the non-profit sector from the comparator group, does that imply that FBC would not potentially hire executives from these sectors?

Response:

The comparator group is used to create a comparator market when FBC is determining its compensation programs for executives. The comparator group is a broad spectrum of organizations with which FBC would normally compete for talent; however, this does not imply that FBC would only hire executives from those sectors included in the comparator group.

220.3.2 Is it possible that FBC may hire executive resources from the public sector, particularly from local public sector electricity organizations such as BC Hydro, Columbia Power, or Nelson Hydro?

Response:

In searching for executive talent, FBC may hire qualified, competent resources from any sector, including the public sector and the above referenced companies, so long as the individual meets the requirements of the role

220.3.3 Can FBC benchmark total executive compensation levels on a percentile basis using 50/50 weighting of private and public sector organizations for the comparator group similar to the methodology identified in Ontario Ministry of Energy review panel on executive compensation.

If so, please produce a compensation study with a 50/50 weighting of private and public sector organizations for the comparator group. If FBC cannot produce such a report at this time, how long would it take to produce such a report?

Response:

FBC is not able to produce such a report at this time and would be required to engage the Hay Group (or other compensation consultant) to produce such a report. FBC is advised that conducting this study is estimated to cost $22,500 and would take a minimum of six weeks to complete.

220.4 What is FBC's view regarding the named comparators used by Toronto Hydro (AltaGas Ltd, ATCO Ltd, BC Hydro, Capital Power Corp., Emera Inc., Enbridge Inc., ENMAX Corp., Epcor Utilities, Hydro One, IESO, OEB, Ontario Power Authority, Ontario Power Generation, SaskPower, TransAlta Corp. and Union Gas) as their reference group for benchmarking of executive compensation? Are these appropriate comparators for FBC, please explain.

Response:

Please refer to response to BCUC IR 1.219.1.1 for an explanation as to how the current reference group companies are an appropriate comparator for FBC.

220.4.1 Please indicate in what ordinal position FBC would rank against the Toronto Hydro named comparators for both total company revenues and total number of employees.

Response:

This information is not readily available and would likely require FBC to engage a consultant to conduct a further study of the regulated utilities in FBC's peer reference group. Conducting the study would be time-consuming and costly for FBC customers.

220.4.2 Please benchmark current levels of FBC executive compensation on a percentile basis using the Toronto Hydro named comparator group. Also please size adjust the data based on FBC's annual revenue against that of the comparator group. If FBC is not able to do this, please provide an estimate regarding the length of time and effort needed to do so.

Response:

FBC is unable to produce such a report at this time and would be required to engage the Hay Group (or other compensation consultant) to produce such a report. FBC is advised that conducting this study is estimated to cost $19 thousand and would take a minimum of five weeks to complete.

220.5 What is FBC's view regarding the legislation passed by the government of Nova Scotia regarding executive compensation at Nova Scotia Power? Would executive compensation comparable to Nova Scotia Power have merit for FBC? How would such a policy impact FBC rate payers?

Response:

The question does not specify the legislation at issue here. Based on the Company's review and research, the relevant legislation appears to be section 64B of the Public Utilities Act, R.S.N.S. 1989, c. 380 (the PUA).

Section 64B has two aspects dealing with executive compensation. First, the PUA requires Nova Scotia Power to submit a report identifying its executive employees and the remuneration to which they are entitled to the Nova Scotia Utility and Review Board (the Nova Scotia Board) for review and approval with each application for a general rate increase. Second, the PUA states that Nova Scotia Power may not recover from any rate, charge or fee (1) any bonus or incentive compensation, or (2) any other remuneration, except as prescribed by the regulations, paid to executives. Under the associated regulation, Nova Scotia Power may recover only an approximately median base salary for executives and other benefits and compensation totalling no more than 13% of base salary for its executives through rates, charges or fees.

It is FBC's view that it would not be appropriate for British Columbia to pass legislation similar to section 64B of the PUA, and that such a policy would have an overall negative impact on FBC's ratepayers.

With respect to the first aspect of the PUA, requiring Nova Scotia Power to submit for approval a report on executive compensation, similar regulatory oversight is already in place in British Columbia. As is required by the *Utilities Commission Act*, FBC must seek Commission approval of its revenue requirements and any rate increases. These applications have, and will continue to include consideration of FBC's executive compensation programs, including the portions of the program that will be funded by rate payers as opposed to shareholders. Accordingly, implementing a further requirement that FBC submit an executive compensation report would be redundant.

With respect to the second aspect of the PUA, it is FBC's view that such a policy should not be implemented in British Columbia for the following main reasons.

First, as is stated in section 4.17.2.3 of the Application, the executives provide strategic direction, leadership and management for the Company, and therefore are important assets to both the Company and its customers. For the benefit of ratepayers, the Company needs to be able to recruit, retain and motivate qualified and experienced executives.

The Company's executive pay program is comprised of four elements (base play, short-term incentive pay, long-term incentive pay and benefits), which comprise a "Total Rewards Package" of compensation for executives. Each of these four elements work in conjunction, contributing to FBC being able to successfully deliver on both short and long-term corporate objectives, which in turn supports the needs of both the business and its customers. Thus, such costs as the Company seeks to recover and that the Commission determines to be prudent are recoverable from ratepayers.

Second, in the case of Nova Scotia Power, the PUA restricts the discretion of the Nova Scotia Board in determining what portions of compensation are properly included as regulated expenses. Implementing similarly restrictive policies in British Columbia ignores the important role that the incentives play in the Total Rewards Package and to the Company and its customers.

FBC has designed its Total Rewards Package to attract, maintain and motivate qualified and experienced executives, through recognizing market pay and acknowledging competencies and skills of individuals. As a general policy, FortisBC establishes its base and incentive compensation targets so as to compensate executives at a median level of a broad reference group of Canadian commercial industry companies as determined by leading third party experts in the field. This reference group reflects the fact that the Company seeks to attract executives from a broad range of industries, and that these are sectors where FBC also sees a flight risk. Overall, the Total Rewards Package is designed to provide executives with competitive levels of compensation.

FBC's short and long-term incentive pay is an important part of the Total Rewards Package. The use of incentive programs is generally accepted as a standard element in executive compensation and is essential to FBC being able to provide a competitive compensation package. In addition to ensuring that FBC is able to attract the best executives to the Company, incentives focus executives' attention on sustained, customer-value creation. As FBC's incentives are tied to specific targets related to customer service, cost control, safety and reliability, they motivate executives to achieve results that directly create value for customers. Given the relation between value for customers and the incentive programs, it is important that the Commission retain the ability to determine whether all forms of executive compensation should be included as a regulated expense. As explained in the point above, such costs as the Company seeks to recover and that the Commission determines to be prudent are recoverable from ratepayers.

Third, the Nova Scotia legislation is inconsistent with what the Commission has previously determined to be reasonable and just with respect to executive compensation. For example, in Order G-110-12 with respect to FBC's Application for Approval of its 2012-2013 Revenue Requirements, the Commission acknowledged "that there is a need for both a competitive base pay and an incentive package to attract and retain quality executives." (at p. 58). Adopting legislation similar to that of Nova Scotia would be incompatible with these prior findings.

In summary, FBC believes that it would not be appropriate to implement a policy similar to section 64B of Nova Scotia's PSU, and that such a policy would have a negative impact on FBC's customers. These negative impacts arise from the fact that the policy ignores the important role that the current Total Rewards Package plays in creating value for customers (including through allowing FortisBC to attract and retain quality executives and through motivating those executives) and by restricting the discretion that the Commission presently has to determine, on a case by case basis, when specific items of executive compensation should be included as a regulated expense.

221.0 Reference: Exhibit B-1, p. 114

Executive Employees – Compensation Results and Targets

Section 4.3.3.1, page 114 of the PBR application FBC states: "The Company's executive compensation program involves four main elements: base pay; short term incentive pay; long term incentive pay; and benefits."

On page 5 of Form 51-102F6 it states: "Short-term incentives awarded to executives are capped at 150 percent of Annual Salary; however, the Governance Committee retains the discretion to award up to a maximum of 200 percent of Annual Salary in recognition of individual response to exceptional challenges or opportunities and may make deviations in appropriate circumstances." (Exhibit A2-4 FHI Statement of Executive Compensation)

On page 7 of Form 51-102F6 it states: "NEOs participate in an annual incentive plan that provides for annual cash bonuses which are determined by way of an annual assessment of corporate and individual performance in relation to targets approved by the Board of Directors upon recommendation by the Governance Committee. The Corporation's annual earnings must reach a minimum threshold level before any payments are made. The objectives of the annual incentive plan are to reward achievement of short-term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Corporation." (Exhibit A2-4 FHI Statement of Executive Compensation)

Page 9 of Form 51-102F6 – Statement of Executive Compensation, For the Year Ended December 31, 2012 FortisBC Holdings Inc., provides a summary compensation table. As described on page 9, "The following table sets forth information concerning the annual and long-term compensation earned for services rendered in respect of each of the individuals who served as the Chief Executive Officer or Chief Financial Officer during the most recently completed financial year and the three most highly compensated executive officers of the Corporation during the most recently completed financial year."

The summary compensation table follows:

Name and principal position	Year	Salary ($)	Option-based awards ($)[1]	Annual incentive plans ($)[2]	Pension value ($)[3]	All other compensation ($)[4]	Total compensation ($)[5][6][7]
John C. Walker President and CEO FortisBC Holdings Inc.	2012	520,000	255,530	400,000	135,539	44,615	1,355,684
	2011	500,000	277,399	425,000	102,175	56,195	1,360,769
	2010	453,192	186,173	310,000	80,698	94,442	1,124,505
Roger A. Dall'Antonia CFO and Treasurer FortisBC Holdings Inc.	2012	243,345	44,895	165,700	39,485	14,583	508,098
	2011	234,904	48,899	150,000	36,875	16,254	486,932
	2010	222,327	51,985	135,000	31,000	25,237	465,549
Douglas L. Stout Vice President, Energy Solutions and External Relations FortisBC Energy Inc.	2012	275,546	50,806	162,500	46,485	6,575	541,912
	2011	267,590	55,699	170,000	39,566	16,993	549,848
	2010	262,000	63,345	123,000	42,000	18,231	508,575
Cynthia Des Brisay Vice President, Energy Supply and Resource Development FortisBC Energy Inc.	2012	258,356	47,640	178,300	41,485	3,394	529,175
	2011	250,827	52,256	150,000	34,665	8,605	496,353
	2010	241,661	58,512	102,000	33,000	28,043	463,216
Dwain A. Bell Vice President, Operations FortisBC Energy Inc.	2012	245,789	45,333	125,000	67,485	144	483,751
	2011	234,904	48,899	125,000	10,805	10,496	430,104
	2010	230,000	55,619	96,000	10,000	7,902	399,521

(Exhibit A2-4 FHI Statement of Executive Compensation)

221.1 What are the specific performance targets used by FBC to make decisions regarding incentive pay?

Response:

The specific performance targets used by FBC to make decisions regarding incentive pay for executives are included in the FBC corporate scorecard and each executive member's individual performance objectives.

Please refer to Attachment 221.1 for the 2013 short term incentive plan targets approved by the Governance Committee of the Board of Directors.

221.1.1 When are performance targets set? How frequently are they revised?

Response:

Performance targets are revised and set annually for both the FBC corporate scorecard and individual performance objectives. Performance targets may also be revised if circumstances warrant, for example, to reflect a midyear revenue requirements decision.

221.1.2 For each FBC executive please provide historical short-term incentive compensation awards for each of the last five years. Please express these awards as a percentage of annual salary.

Response:

Please refer to the table below for a summary of short-term incentive payments to individual executives for the last five years, expressed as a percentage of annual salary.

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%

221.1.3 Please explain why FBC targets executive compensation such that STI (annual incentive plans) makes up a much larger component of compensation compared to LTI (option based awards)?

Response:

The objectives of the annual incentive or STI plan are to reward achievement of short term financial and operating performance and focus on key activities and achievements critical to the ongoing success of the Corporation. FBC targets the proportion of STI, combined with base salary, to reflect the market median. Based on the Hay Group's Executive Compensation Review, FBC's current STI targets (as a percentage of salary) are within market norms. Please refer to Attachment 226.1.1 for a copy of this review. Please also see Attachment 221.1.3 for a letter from the Hay Group summarizing its findings.

In contrast, LTI seeks to provide incentives for achieving sustained business performance over time. According to FBC policy, the option grant for an executive is determined by first multiplying a specified percentage of salary by the executive's current salary. The product of this is then divided by the strike price of the option grant (i.e. Fortis Inc. share price) to determine the number of options granted. The value of the grant is based on Black-Scholes methodology. The proportion of compensation addressed by LTI is also intended to be market-competitive. However, LTI value is affected by market factors and therefore may be below target. In recognition of this, LTI compensation has been augmented by the introduction of PSUs, which complement the current stock option plan and ensure that management is focused on the long term success of the organization. The cost of the PSU plan is not recovered in rates.

221.2 Are there any other items of total executive compensation that are not covered under base pay; short term incentive pay; long term incentive pay; and benefits? If so please list and explain them.

Response:

There is one additional item of total executive compensation included in FBC's executive compensation program. Each member of the executive team is provided with the use of a company vehicle, the value of which has a pre-determined maximum based on the position. All maintenance and operating costs are paid by FBC. The cost of this is included in O&M Expense.

221.2.1 Does FBC benchmark the executive benefit component of compensation against a reference group? If so, how is done?

Response:

Compensation comparisons to a reference group for executive employees generally include base salary and incentive pay only. However, in 2011, FBC engaged Towers Watson to conduct a review of the competitiveness of the Company's pension and benefit programs, including vacation, holidays and other paid time off. This review resulted in the alignment of leave provisions within the executive team of the utilities and brought the value of the pension and benefits program to approximately market median.

Please refer to Attachment 221.2.1 for a copy of this review.

FBC reviews all elements of its compensation program regularly to ensure that its offerings are market-competitive in order to allow it to retain (and attract, where appropriate) competent executive talent.

221.3 How are pensions and pensionable earnings reflected in total annual executive compensation when compared to the reference group?

Response:

The pension provisions provided to FBC executives are market competitive and include an RRSP and supplemental retirement (SERP) provision. The SERP provides for the accrual of 13% of earnings in excess of the Income Tax Act RRSP limit.

In June of 2011, an Executive Pension and Benefits Review was conducted by Towers Watson (please refer to Attachment 221.2.1 provided in response to BCUC IR 1.221.2.1). The Company-provided value of the pension (RRSP and SERP) provided to FBC Executives was tested against a peer group. The pension value for the executive group was found to be approximately the median of the peer group used in that study.

In response to a BCUC directive, in May of 2013, FEI engaged the Hay Group to perform a review which included FBCs SERP pension arrangement. The Hay Group found the annual total employer contribution rate of FBC's retirement benefits (RRSP and SERP) to be within the norm of other executive retirement programs in the commercial industrial reference group. Please refer to the response to BCUC IR 1.226.1.1, Attachment 226.1.1.

221.4 What human resource metrics does FBC use to make decisions regarding executive performance and compensation? Please list and explain each metric.

Response:

Specific human resource metrics are not used by FBC to make decisions regarding executive performance and compensation.

HR objectives may be included as individual executive performance objectives.

221.5 Please list and explain each performance metric, as well as the targets used to evaluate whether the performance metric has been reached.

Response:

Please refer to the response to BCUC IR 1.221.4.

221.5.1 Please explain how each approved performance metric for base pay, STI, and LTI relate to shareholder interests as well as rate payer interests. Please do this for all performance metrics. Use the six tables below as a guide.

Base Pay Performance Metric	**Shareholder Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Base Pay Performance Metric	**Ratepayer Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Short-term incentive Performance Metric	**Shareholder Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Short-term incentive Performance Metric	**Ratepayer Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Long-term incentive Performance Metric	**Shareholder Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Long-term incentive Performance Metric	**Ratepayer Interests**		
	Not Related (0)	Indirectly Related (1)	Directly Related (2)
Metric 1			
Metric 2			
Metric 3			
Metric ...			

Response:

Please refer to the response to BCMEU IR 1.13.1 for a description of the elements of executive compensation at FBC, including base salary, STI and LTI.

Performance metrics are not an element of base salary or long-term incentive pay.

Short-term incentive pay, however, is determined based on achievement of corporate and personal performance objectives.

Please refer to the table below for a summary of how FBC's corporate objectives for short-term incentive pay are related to ratepayer and shareholder interests. Individual objectives are not included in this Table, because the degree to which they are related to ratepayer and shareholder interests is dependent on the individual objective. All are designed to balance the interests of stakeholders, customers, and the shareholder.

FBC's Corporate Objectives for STI and How They are Related to Ratepayer and Shareholder Interests

Short-term Incentive Performance Metric	Ratepayer Interests	Shareholder Interests
Financial	Directly related	Directly related
Safety	Directly related	Indirectly related
Customer	Directly related	Indirectly related
Regulatory	Directly related	Directly related

All of the measures currently included in the scorecard have an effect on both customer and shareholder interests. Customer measures are focused on ensuring the Company is able to deliver a safe and reliable service while maintaining a customer service focus. Safety measures help to ensure focus on achieving employee safety through lost time and vehicle accidents. Creating a safe working environment for employees will support the delivery of a safe and reliable service to customers. Regulatory performance highlights the importance of achieving success on regulatory issues and agreements for the benefit of both customers and the shareholder. The financial measure recognizes the importance of achieving a reasonable return and ensuring a financially, healthy company.

Please refer to the response to BCSEA IR 1.34.2, Attachment 34.2 for copies of FBC's corporate scorecards for the years 2008-2012.

221.6 How are vacation time, other time-off, and work hours reflected in total annual executive compensation when compared to the reference group?

Response:

Compensation comparisons to the reference group for executive employees generally include base salary and incentive pay only. However, in 2011, FBC engaged Towers Watson to conduct a review of the competitiveness of the Company's pension and benefit programs, including vacation, holidays and other paid time offSubsequent to this study, FBC aligned executive leave provisions.

Please refer to the response to BCUC IR 1.221.2.1, Attachment 221.2.1 for a copy of this review.

221.7 How is job security and employee position turnover reflected in total annual executive compensation when compared to the reference group?

Response:

FBC's executive compensation philosophy is designed to provide market-competitive compensation which allows FBC to retain (and attract, where required) qualified, competent executive talent.

FBC believes that its executive compensation offerings are appropriately positioned to mitigate the risk of turnover on its executive team.

221.8 Please confirm that any stock options and its related costs have not been recovered from FBC ratepayers in the last five fiscal years and are not proposed to be recovered from ratepayers in the proposed test years.

Response:

The executive stock option plan and its related costs have not been recovered from FBC ratepayers in the last five fiscal years and are not proposed to be recovered from ratepayers in the 2014 through 2018 period.

222.0 Reference: Exhibit B-1, p. 115

M&E Employees

On page 115 of the Application (Exhibit B-1), Section 4.3.3.2 (M&E Employees), FBC states: "As a general policy, FBC establishes base salary and incentive compensation targets at the median level of a peer group of companies. The peer group is representative of a commercial/industrial group with an emphasis on natural resources and utilities."

222.1 For M&E employees, does FBC engage a compensation consultant or review compensation studies when establishing compensation targets? If so, please produce all sources relied upon over the last five years to set M&E employee compensation at the median level. If no, how does FBC determine the median level in order to set targets?

Response:

FBC has engaged the services of the Hay Group and Towers Watson to assist with establishing annual compensation.

FBC engages its primary compensation consultant, the Hay Group as required for M&E compensation matters. In addition, on an annual basis FBC subscribes to the Hay Group Compensation Planning Update Bulletins, which provide forecasts for base salary policy and base salary actuals for the year ahead, including anticipated increases and base salary policy movement. This data permits FBC to obtain information relative to Canadian economic and national and regional salary forecasts.

FBC also annually participates in and subscribes to the Hay Group Total Compensation Survey and the Conference Board of Canada Compensation Outlook survey. FBC also remains abreast of Stats Canada information and BC economic reporting information. Survey results and Stats Canada information are accessed on-line and are not available to include as attachments.

The primary sources FBC has relied upon over the last five years to set M&E employee compensation are provided in CONFIDENTIAL Attachment 222.1, being filed under separate cover confidentially as it contains commercially sensitive compensation information for planning purposes.

222.2 On what basis is the representative commercial/industrial peer group for M&E employees chosen?

Response:

The basis for the selection of the representative commercial/industrial peer group for M&E compensation is described in Attachment 222.2 which is a letter from the Hay Group.

Selection of a common representative commercial/industrial peer group for the FortisBC gas and electric utilities supports HR's efforts toward the alignment of the utilities. The establishment of a common M&E compensation platform creates efficiencies in the area of compensation administration and supports equity among the utilities and movement of staff throughout the FortisBC Group of Companies facilitating operational flexibility and employee growth and development.

222.2.1 Please list the companies that are part of the commercial/industrial peer group for M&E employees.

Response:

The companies that are part of the commercial/industrial peer group for M&E employees are:

Ainsworth Engineered Canada L. P.	Air Products Canada Ltd.
ALS Canada Ltd.	AltaSteel Ltd.
Aluminerie Alouette Inc.	ArcelorMittal Dofasco Inc.
Babcock & Wilcox Canada Ltd.	Barrick Gold Corporation
Bekaert Canada	BHP Billiton - Ekati Diamond Mines
Bluewater Power Distribution Corporation	British Columbia Hydro and Power Authority
British Columbia Safety Authority	Bruce Power L.P.
Campbell Company of Canada	Canadelle Inc.
Canadian National Railway Company	Canadian Pacific Railway
Canexus Corporation	Canfor Pulp Limited Partnership
Canpotex Limited	Cargill Limited
Caterpillar of Canada Corporation	Centerra Gold Inc.
Daishowa-Marubeni International Ltd.	De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division	De Beers Canada Inc., Mining Division
Dow Chemical Canada Inc.	Dundee Precious Metals
E.I. du Pont Canada Company	Elkem Métal Canada Inc.
Enbridge Gas Distribution Inc.	Enersource Hydro Mississauga Inc

ERCO Worldwide	Essar Steel Algoma Inc.
Finning (Canada)	Finning International Inc.
Fortis Inc.	Fortis Properties Corporation
FortisAlberta Inc.	FortisOntario Inc.
General Kinetics Engineering Corporation	Guelph Hydro Electric Systems Inc.
Halifax Regional Water Commission	Hecla Mining Company
Hydro One Brampton	Hydro One Inc.
IAMGOLD Corporation	Industry Training Authority
Ingersoll-Rand Canada Inc.	INVISTA (Canada) Company
Kinross Gold Corporation	Kuehne + Nagel Ltd.
Lantic Inc. - Rogers Sugar Division	Maritime Electric Company
McElhanney Consulting Services Ltd.	McElhanney Land Surveys Ltd.
Minas Basin Pulp & Power Co. Ltd.	Mitsubishi Canada Limited
Newfoundland Power Inc.	Newmont Mining Corporation of Canada Limited
NOVA Chemicals Corporation	Nova Scotia Power Inc.
Ontario Power Authority	Ontario Power Generation Inc.
Oshawa PUC Networks Inc.	Pan American Silver Corporation
Potash Corporation of Saskatchewan Inc.	Praxair Canada Inc.
Rio Tinto - Diavik Diamond Mines	Rio Tinto Iron Ore
Russel Metals Inc.	Saint-Gobain Abrasives Canada Inc.
SaskEnergy Incorporated	SaskPower
SaskTel	Schneider Electric
Sherritt Coal	Sherritt International Corporation
Shore Gold Inc.	Sofina Foods Inc.
Suncor Energy Inc.	Teck Resources Limited
Teck Resources Limited - Trail Operation	Teck Resources Limited - Highland Valley Copper
Teekay Corporation	Tembec Inc.
The Churchill Corporation	The McElhanney Group Ltd.
The Mosaic Company	Tolko Industries Ltd.
Toronto Hydro-Electric System Limited	Twin Rivers Paper Company
Ultramar Ltée	VPL Enterprises Ltd.
West Fraser Timber Co. Ltd.	Xstrata Copper Canada
Xstrata Nickel Canada	Xstrata Zinc Canada
Yukon Energy Corporation	Zellstoff Celgar Partnership Limited

222.2.2 Please elaborate in detail on how these reference group companies are appropriate comparators for FBC?

Response:

Please refer to the response to BCUC IR 1.222.2, and Attachment 222.2 for a description of the basis for the selection of the representative commercial/industrial peer group for M&E compensation.

222.2.3 Where does actual compensation for FBC M&E employees, rank against the comparator group?

Response:

Average actual compensation for FBC M&E employees for 2013 is at 95% of the market median for the various ranges.

222.3 Please explain and quantify the various components of M&E employee compensation.

Response:

The two main components of the M&E compensation program are:

1. base pay; and
2. short-term incentive pay.

Base pay is designed to maintain market competitiveness at a level permitting FBC to attract and retain quality talent. FBC's base pay structure for M&E employees includes five broad bands within four job families that positions are matched to using the Hay job evaluation system. Salary ranges are set around the job rate at 80% of the job rate for the range minimum and at 110% of the job rate for the range maximum. Individual salaries are reviewed annually with annual adjustments made within an overall corporate budget. The adjustments at the individual level are performance based.

Short-term incentive pay recognizes and rewards the achievement of individual and corporate objectives by putting compensation at risk. The value of short-term incentive pay assigned to each broad band is positioned at approximately the market median for the peer group and ranges from 5-25% of regular earnings, with the maximum payout set at 150% of target. The amount of incentive pay is based 50% on the achievement of individual objectives, and 50% on the achievement of corporate objectives.

222.4 What human resource metrics does FBC use to make decisions regarding M&E staffing levels at FBC? Please list and explain each metric.

Response:

FBC does not use human resource metrics to make decisions regarding M&E staffing levels. Decisions regarding M&E staffing levels are made at the departmental level, taking into account such factors as forecasted work volume and organization of the department.

222.4.1 Please provide the following HR Metrics for FBC M&E Employees for the last five years: 1) Hire Cycle Time, 2) Separation Rate, 3) Total Hire Rate, 4) External Hire Rate, 5) Span of Control, 6) Variable Compensation Ratio.

Response:

Please refer to the table below for information regarding the HR metrics listed above.

HR Metrics for FBC M&E Employees for the Last 5 Years

	2008	2009	2010	2011	2012
Hire Cycle Time (Days)	*	*	*	*	53.3
Separation Rate	17.16%	9.35%	8.51%	12.68%	7.19%
Total Hire Rate	26.87%	13.67%	8.51%	14.79%	14.38%
External Hire Rate	14.18%	11.51%	6.38%	6.34%	9.15%
Span of Control	n/a	n/a	n/a	n/a	n/a

* *Hire cycle time was not tracked prior to 2012; data for these years is unavailable and the metric would take a great deal of time to determine retroactively.*

FBC has defined these metrics to mean as follows:

1. Hire Cycle Time: the number of days from the date a job is posted to the date the offer letter is sent to the successful applicant;
2. External Hire Rate: the number of external M&E hires, divided by M&E headcount;
3. Separation Rate: is the number of M&E employees terminated involuntarily, retired, and terminated voluntarily, divided by M&E headcount;
4. Total Hire Rate: the number of new M&E hires, divided by M&E headcount (where new hires includes any external hires, plus employees moving from temporary to regular status);
5. Span of Control is not a metric that FBC tracks.

Regarding Variable Compensation Ratio, FBC M&E employees short term incentive pay targets are associated with the salary band for their position.

Variable compensation ratios differ, depending on the salary band the M&E position falls into, as well as the individual employee's performance. The incentive pay targets by salary band are shown below:

Band	Target
5	20%
4	15%
3	10%
2	10%
1	5%

222.4.2 Also, provide the anticipated values for the proposed test years for the above HR Metrics?

Response:

The HR metrics listed in the response to BCUC IR 1.222.4.1 are not regularly measured at FBC as they are not used to make decisions regarding M&E staffing levels. Values for the proposed test years have not been forecast.

222.5 How are vacation time, other time-off, and work hours reflected in total annual M&E employee compensation when compared to the reference group?

Response:

Compensation comparisons to the reference group for M&E employees generally include base salary and incentive pay only. However, in 2011, FEI and FBC engaged Towers Watson to conduct a review of the competitiveness of M&E pension and benefit programs as it worked toward alignment of its M&E compensation platform between the gas and electric utilities. The review considered vacation, holidays, and paid time off and concluded that FBC M&E employees were slightly below the market median. In response to this FBC transitioned employees to a flexible benefits program that included aligned vacation and time off practices.

Please refer to Attachment 222.5 for a copy of this review.

222.6 How is job security and employee position turnover reflected in total annual M&E employee compensation when compared to the reference group?

Response:

FBC's compensation philosophy for M&E employees is to target compensation at the market-median specifically to attract and retain qualified, competent talent.

Job security and employee position turnover are not otherwise reflected in total annual M&E employee compensation at FBC when compared to the reference group.

222.7 How is the span of control reflected in total M&E employee compensation when compared to the reference group?

Response:

Job family role profiles used to evaluate all M&E jobs were developed utilizing the Hay Group job evaluation methodology, which measures job factors commonly known as the input (knowledge, skills and abilities), throughput (problem solving) and output (accountability). Span of control is reflected within the assessment of these Hay Group factors.

222.8 How are pensions and pensionable earnings reflected in total annual M&E compensation when compared to the reference group?

Response:

Pensions and pensionable earnings have not historically been included in total annual M&E compensation when compared to the reference group. However, in 2011, FBC engaged Towers Watson to determine the Company's benefits values for M&E employees relative to market. The value of pensions for FBC M&E employees was found to be at approximately the market median.

Please refer to the response to BCUC IR 1.222.5, Attachment 222.5 for a copy of this study.

223.0 Reference: Exhibit B-1, p. 116

Unionized Employees

On page 116 of the Application (Exhibit B-1), Section 3.3.3.3 (Unionized Employees) FBC states: "Recent agreements with the IBEW and COPE focus on competitive rates of pay, productivity, retention of management rights and cost effectiveness. Negotiated settlements that include general wage increases also include saving offsets in other compensation and benefit areas."

223.1 For unionized employees, how does FBC establish competitive rates of pay for each of COPE and IBEW?

Response:

Rates of pay for all of FBC's unionized employees are contained in the applicable collective agreement and are the subject of negotiated agreements reached with the respective union. FBC's approach to compensation for unionized employees is to provide market-competitive wages within certain job classifications by reviewing market survey data and comparable negotiated settlements.

For COPE Customer Service employees, a joint commitment to market competitiveness is included in the Collective Agreement as a Letter of Understanding. Please refer to Attachment 223.1 for a copy of the Letter of Understanding.

223.1.1 Does FBC engage a compensation consultant or review compensation studies when establishing compensation for each of the unionized employee groups? If so, please produce all sources relied upon over the last five years for each of the unionized employee groups.

Response:

FBC seeks to set bargaining unit wage rates that are market competitive in order to be able to attract and retain quality talent.

1. COPE: FBC has not engaged a compensation consultant or reviewed compensation studies to establish compensation for the COPE group of employees within the past five years. However, FBC regularly subscribes to and remains abreast of BC labour market and bargaining bulletins, economic reporting, Stats Canada information, including the

consumer price index and other related information. Much of this material is accessed on-line and is not available to include as attachments.

2. IBEW: FBC has not engaged a compensation consultant or reviewed compensation studies to establish compensation for the IBEW group of employees within the past five years. However, FBC conducted its own review of wage rates for comparable jobs with comparable organizations, including member organizations from the Canadian Electricity Association. FBC also reviewed publicly available collective agreements and corresponding wage rates.

   Please refer to Attachment 223.1.1 for a copy of these reviews.

3. COPE Customer Service: FBC adopted the terms of the applicable collective agreement between FEI and COPE with respect to the Customer Service group of employees when a certain group of FBC employees were amalgamated into this bargaining unit. Going forward, per a Letter of Understanding included in the collective agreement, a joint market comparator survey is to be conducted in advance of the collective agreement expiring. Please refer to Attachment 223.1 provided in response to BCUC IR 1.223.1, for a copy of the Letter of Understanding, which also identifies the compensation elements to be surveyed and the comparator group of companies.

223.1.2 Please explain and quantify the individual compensation components for each of the unionized employee groups.

Response:

Compensation components for each of the unionized employee groups at FBC are as follows:

1. COPE: Base pay is the single component of compensation for the COPE employee group. Base pay is negotiated for 9 successive salary groups; each salary group contains 5 steps. Jobs are assigned to a salary group according to a joint job evaluation plan, and employees progress along the steps of a salary group based on time in a job.

2. IBEW: Base pay is the only component of compensation for the IBEW employee group. Base pay is negotiated for each job.

3. COPE Customer Service: Compensation for COPE Customer Service employees includes base pay and short-term incentive pay. Base pay is negotiated for 10 successive salary groups; each salary group contains 5 steps. Jobs are assigned to a salary group through joint agreement with the union, having regard to market

competitiveness. Incentive pay for eligible employees can be up to 3.5% of regular earnings, based upon corporate, departmental and individual performance within specific metrics. Only those employees hired after March of 2012 are eligible for incentive pay.

Compensation for each of the unionized employee groups follows FEI's philosophy of providing market-competitive compensation in an effort to retain and attract qualified, competent employees.

223.2 How are vacation time, other time-off, and work hours reflected in each of the unionized employee groups' annual compensation when compared to the appropriate reference group(s)?

Response:

Generally, only base pay and incentive pay have been considered in any compensation comparisons or reviews for market competitiveness.

223.3 How is job security and employee position turnover reflected in each of the unionized employee groups' compensation when compared to the appropriate reference group(s)?

Response:

FBC's philosophy for unionized employees is to provide compensation that is market-competitive to attract and retain qualified, competent talent.

Job security and employee position turnover are not otherwise reflected in any of the unionized employee groups' compensation at FBC when compared to the appropriate reference groups.

Please refer to the response to BCUC IR 1.223.1.2 for a description of the individual compensation components of the unionized employee groups, and to the response to BCUC IR 1.223.1 for information around how competitive rates of pay for each of the unionized employee groups are established.

223.4 What human resource metrics does FBC use to make decisions regarding unionized staffing levels at FBC? Please list and explain each metric.

Response:

FBC does not use human resource metrics to make decisions regarding unionized staffing levels. Staffing decisions are made at the departmental level, based on forecasted work volume.

223.5 Please provide the following HR Metrics for FBC unionized staff for the last five years: 1) Hire Cycle Time, 2) Separation Rate, 3) Total Hire Rate, 4) External Hire Rate, 5) HR Staff to Full-Time Equivalent Ratio.

Response:

FBC manages its unionized workforce deliberately and consistent with corporate objectives to:

1. Provide service at a reasonable cost; and
2. Action efficiencies continuously as opportunities present.

The table below provides a historical review of the metrics requested and supports this conclusion.

HR Metrics for FBC Unionized Staff for the Last 5 Years

	2008	2009	2010	2011	2012
Hire Cycle Time (Days)	*	*	*	*	47.5
Separation Rate	7.73%	5.01%	6.32%	10.09%	6.65%
Total Hire Rate	13.33%	4.18%	3.45%	13.65%	8.16%
External Hire Rate	5.87%	1.67%	2.59%	5.34%	4.83%
HR Staff to Full-Time Equivalent Ratio	1:39	1:41	1:38	1:48	1:39

** Hire cycle time was not tracked prior to 2012; data for these years is unavailable.*

FBC has defined these metrics to mean:

1. Hire Cycle Time: the number of days from the date a job is posted to the date the offer letter is sent to the successful applicant.
2. External Hire Rate: the number of external union hires, divided by union headcount.
3. Separation Rate: is the number of union employees terminated involuntarily, retired, or who terminated voluntarily, divided by union headcount;
4. Total Hire Rate: the number of new union hires, divided by union headcount (where new hires includes any external hires, plus employees moving from temporary to regular status).

Total Hire Rate in 2010 and 2011 increased due to a number of entry-level, multi-incumbent temporary positions being filled. External Hire Rate also increased in 2010 and 2011, for the same reason.

Note that FBC continues to look at each vacancy as an opportunity to explore efficiencies.

The ratio of HR staff to FBC FTEs has remained fairly constant over the period in question, with the exception of 2011. FBC's HR department continues to reinforce its commitment to finding efficiencies by supporting corporate FTEs without adding HR staff.

223.5.1 Also, provide the anticipated values for the proposed test years for the above HR Metrics?

Response:

The HR metrics listed in the response to BCUC IR 1.223.5 are not regularly measured at FBC as they are not used to make decisions regarding unionized staffing levels. Values for the proposed test years have not been forecast.

224.0 Reference: Exhibit B-1, p. 160

Human Resources

On page 160 FBC states that, "the overall goal of Human Resources (HR) is to ensure that the Company's workforce, now and into the future, has the level of skill and capacity to achieve its business goals and objectives. The Human Resources department performs and provides different services to support management of the workforce to ensure effective and efficient alignment with business plans."

224.1 Does FBC participate in a human resources benchmarking group or engage consultants to benchmark FBC'S operational performance? If so, please elaborate.

Response:

FBC participates in various industry groups as HR professionals. While the performance metrics reviewed in those groups are considered, their relevance is dependent on the specific details of the specific metric.

Annually, FBC creates a corporate scorecard to measure different elements of operational performance. In addition, FBC's departments set goals and objectives that support corporate objectives.

224.2 Please submit any documents used to evaluate FBC's operational performance produced over the last five years; e.g., HR Metrics, Benchmarking Studies, Strategic Plans, Progress Reports, etc.

Response:

FBC's primary measure of operational performance is its corporate scorecard. Please refer to FBC's response to BCSEA IR 1.34.2, Attachment 34.2 for copies of FBC's corporate scorecards for the years 2008-2012.

FBC has also committed to maintaining specified levels of service as measured by SQIs. These SQIs reflect areas of service that are important to FBC customers. They are measured and compared to benchmarks on an annual basis. Please refer to FBC's response to BCUC IR 1.70.1 for FBC's historical SQI results.

225.0 Reference: Exhibit B-1, p. 114-115

Executive Compensation Benchmarking

225.1 Please complete the following schedule for each of the roles listed below:

- President &CEO
- EVP HR, Customer and Corporate Services
- EVP Network Services, Engineering and Generation
- VP Energy Solutions & External Relations
- VP Energy Supply & Resource Development
- VP Finance & CEO
- VP Strat Plan, Corporate Development and Regulatory Affairs
- VP Operations Support, Gen Counsel & Corporate Services
- VP Customer Service

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation
	Cost Allocated to Principal Company					
2013						
2012						
2011						
2010						
	Cost Allocated to FortisBC					
2013						
2012						
2011						
2010						

<u>Response:</u>

The table above, which is the Summary Compensation Table from the Annual Information Form, has been prepared for each of the named executive positions. The table has been amended to reflect the method used to allocate costs between the various companies.

For each of the named positions, the left side of the table (to the total compensation paid by principal company) is the total actual compensation, paid by the reflected employer of each of the named positions. The employers consist of FortisBC Inc (FBC), FortisBC Energy Inc. (FEI) and FortisBC Holdings In. (FHI). Certain types of benefits and other compensation that are recovered from affiliates have been removed from the total compensation before allocation to the affiliated company as amounts have not been paid for by rate payers.

Please refer to the response to BCUC IR 1.144.7 for the method used to add labour loading to arrive at the amount charged to affiliate companies.

For 2013, certain of the columns are incomplete as the amounts have not yet been determined for 2013.

President & CEO - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FBC								
2013	535,600					537,613	-	537,613	(534,000)	3,613
2012	520,000	255,530	400,000	135,539	44,615	1,357,696	(255,530)	1,102,166	(525,000)	577,166
2011	500,000	277,399	425,000	102,175	56,195	1,362,780	(277,399)	1,085,381	(551,000)	534,381
2010	453,192	186,173	310,000	80,698	94,442	1,126,515	(271,173)	855,342	(287,000)	568,342

EVP HR, Customer and Corporate Services - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FBC								
2013	298,500					298,500	-	298,500	(298,000)	500
2012	290,000	53,450	175,000	50,915	21,374	590,739	(53,450)	537,289	(293,000)	244,289
2011	281,000	58,459	190,000	42,335	9,441	581,235	(58,459)	522,776	(310,000)	212,776
2010	252,846	55,196	131,000	35,475	43,366	517,883	(55,196)	462,687	(128,000)	334,687

EVP Network Services, Engineering and Generation - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FBC								
2013	287,900					287,900	-	287,900	(287,000)	900
2012	264,000	48,651	159,700	44,285	24,472	541,108	(48,651)	492,457	(267,000)	225,457
2011	251,000	52,226	165,000	34,405	5,354	507,985	(52,226)	455,759	-	455,759
2010	230,000	55,619	100,000	32,550	4,398	422,567	(55,619)	366,948	-	366,948

VP Energy Solutions & External Relations - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FEI								
2013	283,700					283,700	-	283,700	(77,000)	206,700
2012	275,546	50,806	162,500	46,485	6,575	541,912	(50,806)	491,106	(78,000)	413,106
2011	267,590	55,699	170,000	39,566	16,993	549,848	(55,699)	494,149	(88,000)	406,149
2010	262,000	63,345	123,000	42,000	18,231	508,576	(63,345)	445,231	(48,000)	397,231

VP Finance & CFO - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FEI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FBC								
2013	260,000					260,000	-	260,000	(259,000)	1,000
2012	243,600	44,895	165,700	39,683	15,236	509,114	(44,895)	464,219	(246,000)	218,219
2011	235,000	48,899	150,000	34,925	11,336	480,160	(48,899)	431,261	(19,000)	412,261
2010	230,000	55,619	120,000	32,550	9,531	447,700	(90,619)	357,081	(9,000)	348,081

1

VP Strat Plan, Corporate Development and Regulatory Affairs - employed by FHI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FHI								
2013	260,000					260,000	-	260,000	(106,000)	154,000
2012	243,435	44,895	165,700	39,485	14,583	508,098	(44,895)	463,203	(103,000)	360,203
2011	234,904	48,899	150,000	36,875	16,254	486,932	(48,899)	438,033	-	438,033
2010	222,327	51,985	135,000	31,000	25,237	465,549	(51,985)	413,564	-	413,564

2

VP Operations Support, Gen Counsel & Corporate Services - employed by FBC

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FHI using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FBC								
2013	249,900					249,900	-	249,900	(289,000)	(39,100)
2012	237,725	43,818	120,600	35,669	18,044	455,856	(43,818)	412,038	(279,000)	176,856
2011	230,800	35,061	125,000	32,819	20,991	444,671	(35,061)	409,610	(260,000)	184,671
2010	225,000	54,402	108,000	31,900	18,581	437,883	(74,402)	363,481	(208,000)	229,883

3

VP Customer Service - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
		Cost Allocated to Principal Company - FEI								
2013	222,500					222,500	-	222,500	(61,000)	161,500
2012	215,806	26,321	100,400	32,485	15,156	390,168	(26,321)	363,847	(61,000)	329,168
2011	205,784	28,572	125,000	25,813	14,635	399,803	(28,572)	371,232	(52,000)	347,803
2010*	189,115	13,230	79,000	29,000	7,934	318,279	(13,230)	305,049	(49,000)	269,279

*Joined executive October 2010

4

VP Energy Supply & Resource Development - employed by FEI

Year	Salary	Option - Based Awards	Annual Incentive Plans	Pension Value	Other Compensation	Total Compensation Paid by Principal Company	Less non regulated awards	Total regulated compensation	Compensation charged out to FBC using an average benefits load	Total Net Compensation Remaining Prior to other recoveries
Cost Allocated to Principal Company - FEI										
2013	266,000					266,000	-	266,000	(145,000)	121,000
2012	258,356	47,640	178,300	41,485	3,394	529,175	(47,640)	481,535	(146,000)	383,175
2011	250,827	52,256	150,000	34,665	8,605	496,353	(52,256)	444,097	(125,000)	371,353
2010	241,661	58,512	102,000	33,000	28,043	463,216	(58,512)	404,704	(55,000)	408,216

225.1.1 For each of the roles listed above, please indicate the principal Company for each role (e.g. FortisBC Holdings Inc.).

Response:

Please refer to the response to BCUC 1.225.1 above.

225.1.2 For each of the roles listed above, please confirm the methodology used to allocate the total compensation costs from the principal company to FBC.

Response:

For the executive roles listed in the table provided in the response to BCUC IR 1.225.1, compensation costs for 2010 to 2013 were allocated from the principal company to FortisBC Energy Inc., FortisBC Holdings Inc. or FortisBC Inc. based on the approach of time estimation, applied against fully loaded Executive costs.

For a discussion on the proposed Massachusetts Formula allocation methodology please refer to the response to BCUC IR 1.144.7.

L. GENERAL

226.0 Reference: Exhibit B-1-3, Appendix C2; Exhibit B-1-2, p. 120

Confidentiality Request

The 2007 BCUC Confidential Filings Directive provides guidance regarding the handling of confidential information in the context of its public hearings.

226.1 Please confirm, or explain otherwise, that segments of Exhibit B-1-3, Appendix C2, were filed on a non-confidential basis in the FBC 2012-2013 Revenue Requirements and Review of ISP proceeding.

<u>Response:</u>

None of the information contained in Appendix C2 was provided in the 2012-2013 Revenue Requirements and Review of ISP (2012-13 RRA) proceeding. Appendix C2 was created by the HAY Group in the beginning of 2013 as a result of the Commission Panel's directive in its Decision on the 2012-13 RRA (Order G-110-12) to provide benchmarking information on all elements of its executive compensation in the next RRA.

226.1.1 Please file a redacted version of Exhibit B-1-3, Appendix C2, on a non-confidential basis.

<u>Response:</u>

Please refer to Attachment 226.1.1 for a non-confidential, redacted version of Exhibit B-1-3, Appendix C2.

226.2 In accordance with the Commission's 2007 Confidential Filings Directive, please file an addendum to the Application requesting to hold the information contained in Exhibit B-1-2 and Exhibit B-1-3 in confidence.

Response:

FBC filed a request for confidentiality in the cover letters of both Exhibit B-1-2 and Exhibit B-1-3 which were filed with the Commission. Attachment 226.2 contains the cover letters only for these exhibits which sets out the basis for requesting confidentiality of these exhibits.

227.0 Reference: Exhibit B-1, p. 108 and Table C3-1

Other Income

Table C3-1 provides Other Income data for 2012 through 2014.

227.1 Please expand the table to include the Other Income actual and approved details from 2008?

Response:

The expanded table below provides the Other Income actual and approved from 2008 as requested.

Other Income ($000s)	Approved 2008	Actual 2008	Approved 2009	Actual 2009	Approved 2010	Actual 2010
Apparatus and Facilities Rental	1,918	2,450	2,304	2,924	2,476	4,005
Contract Revenue	1,955	1,601	1,576	1,400	1,648	1,562
Miscellaneous Revenue	790	652	704	675	686	662
Transmission Access Revenue	-	-	-	-	-	-
Investment Income	367	333	331	188	217	224
Total	**5,030**	**5,035**	**4,915**	**5,187**	**5,025**	**6,453**

Other Income ($000s)	Approved 2011	Actual 2011	Approved 2012	Actual 2012	Approved 2013	Projected 2013	Forecast 2014
Apparatus and Facilities Rental	2,882	3,709	3,384	5,018	3,478	4,184	4,156
Contract Revenue	1,499	1,826	1,714	1,943	1,315	1,709	1,385
Miscellaneous Revenue	899	640	1,157	728	1,203	717	738
Transmission Access Revenue	-	1,151	1,098	1,454	1,071	1,247	1,224
Investment Income	175	180	128	104	98	90	78
Total	**5,455**	**7,506**	**7,481**	**9,247**	**7,165**	**7,947**	**7,582**

228.0 Reference: Exhibit B-1-1, Appendix C5, Wholesale Power Factor Report, p. 1

Power Factor below 0.95

FBC states "There have been sporadic excursions at some delivery points below the 95 percent power factor threshold directed by the Commission in Letter L-9-09."

228.1 Explain the sporadic excursions in terms of the additional VARs required and of kWhs and KWs required, the value of the VARs provided, when they occurred, why they occurred, what is being done to correct the situation and the estimated cost to correct the PF to 0.95.

Response:

In the case of the City of Nelson, there were two excursions below 0.95 PF in July 2012 and August 2011. Both cases occurred during the summer light load periods (where the actual demand was approximately 1/3 or less of the winter peak demand). Other than these two excursions, there is no indication of any systemic problem with the City of Nelson system and hence FortisBC is not taking any specific action beyond ongoing monitoring.

In the case of the City of Grand Forks, the excursions occurred on only one of the three City delivery points. Similar to the City of Nelson, the excursions occurred during lighter load times in the summer months of 2011 and 2012. It is possible that seasonal motor loads (such as irrigation pumping) are contributing to the issue. FortisBC will continue to monitor this delivery point and if power factor excursions continue to be an ongoing problem then the City of Grand Forks may be required to install (at its cost) power factor correction capacitors on their distribution circuit.

Given that the above excursions are occurring at times when the system load is significantly lower than peak, there is no impact to FortisBC system infrastructure and no system reinforcements have been (or will be) required to upply this small excess var consumption.

FortisBC does not directly use var consumption as a billing determinant and hence there is no direct value associated with the vars provided. However, both customers are billed on kWh consumption and on kVA demand. Since kVA metering inherently includes var consumption, these customers are already being penalized for var consumption through higher bills (in that the var consumption results in higher kVA demand charges than if their power factor was maintained at exactly 1.0).

FBC states "Effective March 31, 2013, FBC acquired the utility assets of the City of Kelowna. As a result, the City of Kelowna is no longer a wholesale customer of FBC."

228.2 Did FBC raise the issue of Commission Letter L-9-09 during the review of the Application to acquire the City of Kelowna assets?

Response:

No, FBC did not raise the issue of Letter L-9-09 during the review of the application to acquire the City of Kelowna assets. Further, no information requests were received in that proceeding from the Commission or interveners regarding L-9-09, likely due to the fact that L-9-09 was of limited relevance (if any) to FBC's application to acquire the City of Kelowna distribution assets.

228.3 As the City of Kelowna is no longer a wholesale customer of FBC, does FBC consider that L-9-09 no longer applies to the City of Kelowna?

Response:

Given that L-9-09 directed FBC to implement amended wording in its wholesale agreements with its wholesale customers, and given that the wholesale customer formerly known as the City of Kelowna no longer exists as a result of the approval of FBC's application to acquire the City of Kelowna distribution assets (and the associated indirect customers served by those assets), FBC believes L-9-09 no longer applies to the City of Kelowna.

228.4 What was the City of Kelowna's power factor for the last two years as it was not provided?

Response:

Please see the tables provided below detailing the power factor registered at the delivery points for the former wholesale customer of the City of Kelowna. With the exception of the OKM 5 delivery point, the City of Kelowna maintained a power factor equal to or greater than 0.95 in all months. For OKM 5, the City of Kelowna experienced a power factor less than 0.95 from June 2011 to August 2011, and from May 2012 to September 2012.

	Meter	Date	kW	kVA	PF
Recreation 1	924188	01/03/2013	10110.00	10110.00	1.00
		21/02/2013	12048.00	12048.00	1.00
		22/01/2013	11724.00	11724.00	1.00
		07/12/2012	12120.00	12120.00	1.00
		28/11/2012	10224.00	10224.00	1.00
		24/10/2012	10326.00	10326.00	1.00
		20/09/2012	9402.00	9904.27	0.95
		10/08/2012	11622.00	11783.46	0.99
		13/07/2012	12402.00	12512.87	0.99
		29/06/2012	8724.00	8766.68	1.00
		15/05/2012	8748.00	8763.20	1.00
		02/04/2012	8862.00	8862.00	1.00
		01/03/2012	9468.00	9468.84	1.00
		16/02/2012	11730.00	11765.87	1.00
		18/01/2012	12684.00	12684.00	1.00
		13/12/2011	10770.00	10770.00	1.00
		16/11/2011	10716.00	10716.00	1.00
		26/10/2011	9534.00	9534.00	1.00
		08/09/2011	10104.00	10176.43	0.99
		10/08/2011	12540.00	12540.00	1.00
		06/07/2011	10770.00	10926.38	0.99
		22/06/2011	11526.00	11649.53	0.99
		03/05/2011	9288.00	9288.00	1.00
		20/04/2011	8970.00	8970.00	1.00
		02/03/2011	10242.00	10242.00	1.00

	Meter	Date	kW	kVA	PF
Recreation 2	924180	01/03/2013	10128.00	10128.00	1.00
		21/02/2013	12072.00	12072.00	1.00
		22/01/2013	11766.00	11766.00	1.00
		07/12/2012	12144.00	12144.00	1.00
		28/11/2012	10248.00	10248.00	1.00
		24/10/2012	10356.00	10356.00	1.00
		20/09/2012	9378.00	10386.25	0.90
		10/08/2012	11634.00	11813.58	0.98
		13/07/2012	12366.00	12737.54	0.97
		29/06/2012	8736.00	8787.29	0.99
		15/05/2012	8760.00	8781.35	1.00
		02/04/2012	8886.00	8886.00	1.00
		01/03/2012	9492.00	9492.00	1.00
		16/02/2012	11754.00	11799.22	1.00
		18/01/2012	12720.00	12720.04	1.00
		13/12/2011	10794.00	10794.00	1.00
		16/11/2011	10740.00	10740.00	1.00
		26/10/2011	9552.00	9552.00	1.00
		08/09/2011	10110.00	10194.26	0.99
		03/08/2011	10782.00	11059.07	0.97
		06/07/2011	10752.00	11055.81	0.97
		22/06/2011	11502.00	11903.63	0.97
		03/05/2011	9306.00	9306.00	1.00
		20/04/2011	8988.00	8988.00	1.00
		02/03/2011	10272.00	10272.00	1.00

	Meter	Date	kW	kVA	PF
Saucier	916790	01/03/2013	19026.00	19052.68	1.00
		28/02/2013	21714.00	21761.30	1.00
		22/01/2013	21624.00	21624.00	1.00
		09/12/2012	23274.00	23274.00	1.00
		27/11/2012	19836.00	19836.00	1.00
		29/10/2012	15954.00	15954.00	1.00
		12/09/2012	15474.00	15601.69	0.99
		07/08/2012	19812.00	20256.03	0.98
		09/07/2012	21030.00	21557.56	0.98
		29/06/2012	17544.00	17899.96	0.98
		15/05/2012	15210.00	15210.00	1.00
		10/04/2012	17790.00	17790.00	1.00
		01/03/2012	17640.00	17640.00	1.00
		07/02/2012	19626.00	19626.00	1.00
		18/01/2012	22464.00	22464.00	1.00
		13/12/2011	18786.00	18786.00	1.00
		29/11/2011	16974.00	16974.00	1.00
		26/10/2011	15690.00	15690.00	1.00
		12/09/2011	17268.00	17270.61	1.00
		29/08/2011	18180.00	18196.72	1.00
		06/07/2011	17328.00	17334.32	1.00
		22/06/2011	14568.00	14568.00	1.00
		02/05/2011	13056.00	13056.00	1.00
		05/04/2011	13044.00	13044.00	1.00
		01/03/2011	16440.00	16440.00	1.00

	Meter	Date	kW	kVA	PF
Glenmore	935172	06/03/2013	9126.00	9126.00	1.00
		11/02/2013	10022.40	10146.24	0.99
		13/01/2013	11829.60	11959.34	0.99
		18/12/2012	10810.80	10934.73	0.99
		12/11/2012	10213.20	10346.01	0.99
		23/10/2012	8920.80	9049.23	0.99
		09/09/2012	7822.80	8166.31	0.96
		19/08/2012	11055.60	11675.82	0.95
		13/07/2012	11217.60	11314.29	0.99
		11/06/2012	8924.40	8925.74	1.00
		15/05/2012	9122.40	9123.43	1.00
		16/04/2012	9237.60	9237.60	1.00
		01/03/2012	10846.80	10846.80	1.00
		07/02/2012	12016.80	12016.80	1.00
		18/01/2012	15436.80	15436.80	1.00
		13/12/2011	12618.00	12618.00	1.00
		20/11/2011	11901.60	11901.60	1.00
		31/10/2011	9334.80	9334.80	1.00
		12/09/2011	9457.20	9479.62	1.00
		09/08/2011	10213.20	10263.53	1.00
		06/07/2011	9734.40	9778.27	1.00
		06/06/2011	8283.60	8286.61	1.00
		16/05/2011	6926.40	6926.40	1.00
		18/04/2011	8046.00	8046.00	1.00
		01/03/2011	11034.00	11034.00	1.00

	Meter	Date	kW	kVA	PF
OKM 5	916789	16/03/2013	4082.40	4208.92	0.97
		04/02/2013	4179.60	4302.83	0.97
		22/01/2013	4491.00	4607.51	0.97
		10/12/2012	4082.40	4215.12	0.97
		13/11/2012	4278.60	4419.49	0.97
		24/10/2012	4066.20	4203.05	0.97
		25/09/2012	3747.60	3977.88	0.94
		20/08/2012	4111.20	4376.71	0.94
		13/07/2012	4179.60	4467.14	0.94
		21/06/2012	3506.40	3746.42	0.94
		14/05/2012	3538.80	3809.80	0.93
		17/04/2012	5149.80	5301.27	0.97
		02/03/2012	4179.60	4308.31	0.97
		07/02/2012	4408.80	4543.18	0.97
		18/01/2012	7096.80	7231.57	0.98
		08/12/2011	6067.20	6211.18	0.98
		16/11/2011	6956.40	7115.02	0.98
		26/10/2011	6423.60	6577.82	0.98
		12/09/2011	6358.80	6703.78	0.95
		29/08/2011	6296.40	6692.83	0.94
		28/07/2011	5514.00	5856.59	0.94
		22/06/2011	5544.00	5873.76	0.94
		02/05/2011	5271.60	5480.53	0.96
		07/04/2011	6164.40	6393.98	0.96
		01/03/2011	7113.60	7322.17	0.97

228.5 Will FBC be requesting BCUC to vary Commission Letter L-9-09?

Response:

Although a wholesale agreement with the City of Kelowna no longer exists, the direction provided by the Commission to FBC in L-9-09 still applies to the remaining four wholesale agreements. On that basis, FBC does not plan to seek a variance of L-9-09.

228.5.1 If so, when will FBC make the request?

Response:

Please refer to the response to BCUC IR 1.228.5.

228.6 Please explain the excursions below 0.95 PF and the missing readings for:

- City of Grand Forks – Coalshute , 7 excursions;
- City of Nelson – Rosemount, 2 excursions;
- City of Nelson – Bonnington, several missing readings.

Response:

Please refer to the response to BCUC IR 1.228.1 for a discussion of the excursions below 0.95 PF.

With respect to the "missing readings" for the City of Nelson – Bonnington delivery point, these are in fact intervals during which no energy was delivered or received at this metering point (in other words the incremental meter readings were zero). This occurs because the City of Nelson has multiple transmission interconnections with FBC which can be used to supply its system.

M. DEMAND SIDE MANAGEMENT

229.0 Reference: BC Energy Plan, p. 5; Clean Energy Act (CEA), section 2; Exhibit B-1-1, Appendix H, p.1; BCUC Decision, FortisBC 2012-2013 RR and 2012 ISP (Order G-110-12), pp. 133, 136

Regulatory guidance in setting the DSM funding envelope

The BC Energy Plan states on page 5 "...the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs." The Clean Energy Act (section 2) includes BC energy objectives.

FBC states in the Application "The lower [DSM] program expenditure level will result in lower average customer rates over the test period" (Appendix H, p. 1)

Commission Decision on FBC's 2012-2013 RRA and ISP Application (Order G-110-12) states:

"FortisBC is requesting approval to spend $7.73 million in 2012 and $7.88 million in 2013 on its DSM portfolio...BCSEA's position is that FortisBC is under spending on DSM and should ramp up spending to approximately $33 million per year." (p. 136)

"The Commission Panel recognizes that this acceptance [of FortisBC's 2012 Long-Term DSM Plan] means that FortisBC may simply maintain current levels of DSM spending over the next five years...However,...FortisBC received approval to spend approximately twice the amount on DSM in 2011 over 2010 and was unable to spend to the higher approved level. As well, the Commission Panel acknowledges that the Company is implementing new programs that will take time to gain participants...The Commission Panel is also of the view that the rate impact from DSM spending is a relevant consideration for the public interest, at least in the short term, as increased participation in DSM programs may take some time." (p. 133)

229.1 Does FBC consider it should identify and undertake all cost effective (as as defined by the Demand-Side Measures Regulation) Demand-Side Management (DSM)? If no, please explain why not and if this could result in suboptimal outcomes for customers over the long term.

<u>Response:</u>

FBC believes that the 2013 Conservation Potential Update identifies the technical, economic and program achievable potential in its service area. Generally speaking, the Company undertakes all measures identified as cost-effective by the CPR. However, not all cost-effective measures are conducive to undertake as a program within the FBC service area. For instance, there is potential (53 GWh) for residential Electronics with a TRC benefit/cost ratio of 4.7, which is more effectively addressed by codes and standards changes targeted at manufacturers and distributors.

229.2 Does FBC agree that the level of DSM funding approved in the 2012-2013 RRA and ISP Application was constrained as a result of a concern that FBC would not be able to implement/expand cost effective DSM programs at a fast enough pace in order to spend a higher approved level? If no, please explain why not.

Response:

The 2012-13 DSM Plan and the associated funding was filed, and subsequently approved, based on program participation estimates that factored in a number of market constraints including customer awareness, product and contractor availability, and the level of incentive provided by FBC.

229.2.1 For this Application, has the DSM requested budget been reduced from what would otherwise have been requested as a result of a concern by FBC that it would not be able to spend a higher amount? If yes, please explain.

Response:

No.

229.3 Does FBC consider that customers benefit overall where DSM programs result in lower overall bills, even if rates increase? Please explain.

Response:

It is not possible for rates to increase and for non-participants to have lower bills (all else being equal), and therefore customers cannot benefit overall.

229.4 Does FBC consider that the Commission allowed short-term consideration of rate impacts as part of the DSM selection criteria in the 2012-2013 RRA and ISP Decision a result of a concern that too fast a ramp up of DSM programs could make it hard to ensure equitable access to DSM programs by FBC's customer segments? If no, please explain why not.

Response:

FortisBC considers that the Commission did take rate impact into consideration in approving the 2012-13 DSM expenditures and submits that those considerations are more important in this Application as the spread between retail rates and LRMC increases. The ramp up rate and equitable access are separate considerations, and not necessarily correlated to the rate impact consideration.

229.4.1 For this Application, does FBC consider that it is still unable to ensure equitable access to DSM programs across its customer segments? If yes, please explain why.

Response:

FBC believes it has provided equitable access to DSM programs in the past and that the proposed DSM portfolio continues to provide equitable access to programs.

230.0 Reference: Utilities Commission Act (UCA), s. 44.2 (5); CEA, Section 2; Bloomberg news article, BC's Clean Electricity Same Price as BC Hydro's New Electricity, September 7, 2011[27]

BC Energy Objectives

The Utilities Commission Act states in 44.2 (5): "...the commission must consider...(d)...whether the demand-side measures are cost effective within the meaning prescribed by regulation...(e) the interests of the persons in British Columbia who receive or may receive service from the utility." The Clean Energy Act (section 2) includes BC energy objectives.

A Bloomberg news article titled "BC's Clean Electricity Same Price as BC Hydro's New Electricity" (September 7, 2011) states: "'An increasing reliance on the spot market is not a sustainable long-term environmental solution,' said Andrew Weaver, one of the world's foremost climate scientists and University of Victoria Professor of Earth, Ocean and Atmospheric Sciences. 'Spot market power is dirty power from coal plants and runs contrary to BC's climate action objectives.'"

230.1 Is FBC aware of evidence indicating that BC will or will not meet its BC greenhouse gas (GHG) emission targets over the PBR period? If yes, please provide.

Response:

FortisBC is not aware of evidence indicating whether BC will or will not meet its BC GHG targets.

230.1.1 Is there a plan supporting these BC GHG emission reduction targets which explains what role electricity is required to play (i.e. sector specific targets)? If yes, please provide.

Response:

FortisBC plans are to follow the direction of the Commission, continue to rely on the FBC hydro plants and support the addition of appropriate new resources where practicable to meet BC's energy demands. There are no sector specific targets.

[27] http://www.bloomberg.com/apps/news?pid=newsarchive&sid=ag7BMRDWIKCQ

230.1.2 Please provide a graph showing estimated carbon equivalent emissions from FBC's energy portfolio (including Mid-C purchases) used to meet its customer energy requirements from 2007 to the end of the PBR period. Please provide a breakdown of this data by customer class.

For Mid-C purchases, please assume the generation source is either a combined-cycle gas generator, or renewable energy stripped of its environmental attributes (for example, by sale of its Renewable Energy Certificates) such that its emissions are equivalent to a combined-cycle gas generator. In estimating gas emissions, please include all gas emissions (including venting, flaring and fugitive) related to the final electricity production. Please provide supporting detail and describe all assumptions used.

Response:

The graphs below show the estimated carbon emissions from FBC's energy sources (including Mid C purchases) used from 2007 to 2018 in tonnes CO2 equivalent.

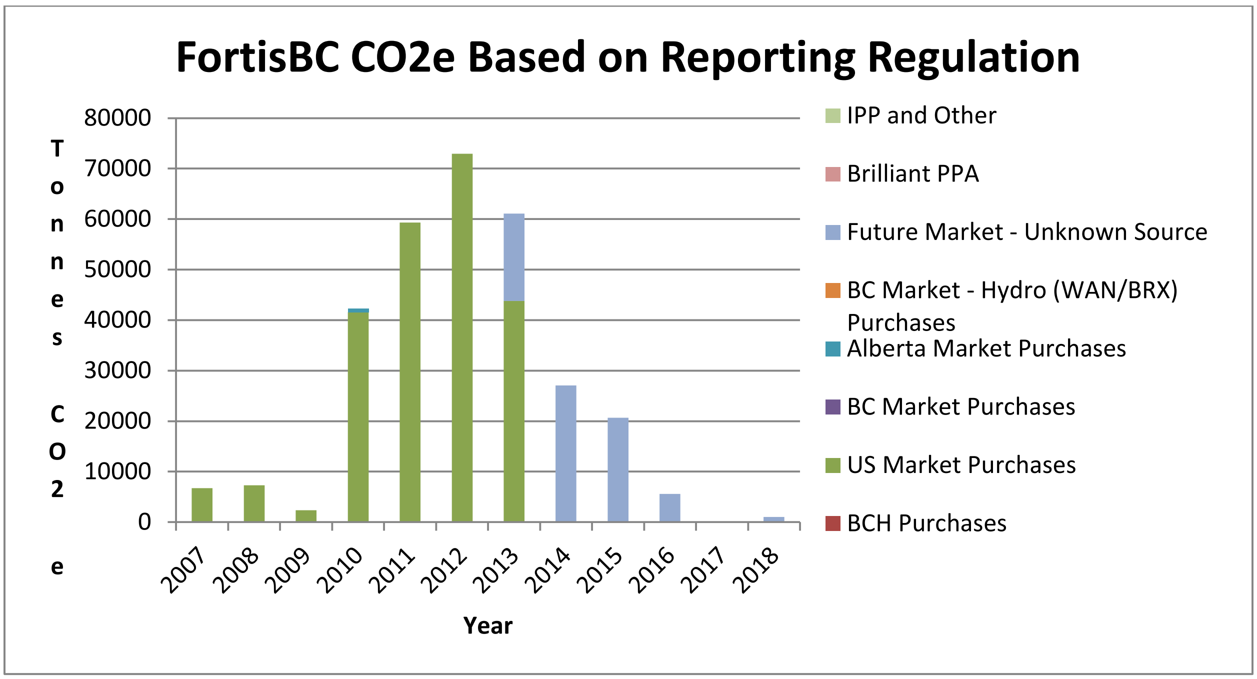
The first graph below shows CO2e volumes based on the BC Reporting Regulation specifications including the use of the Default Emission Factor Calculator (average = 0.102 tonnes CO2e/MWh) for determining CO2e values for the Mid-C energy hub (Washington State). The use of the Western Climate Initiative Emission Factor Calculator average is prescribed by the BC Reporting Regulation and specifies how import power GHG is reported. It is based on an average Carbon Dioxide equivalent (CO2e) for the applicable jurisdiction. The FortisBC provincial resource stack is zero emission so the graph assumptions indicate only previous US Market Purchases and the "Future Market-Unknown Source", assumed 100% at Mid-C, as GHG emission sources. Since not all future market purchases will be from Mid-C, this likely overstates future emissions.

The second graph depicts the requested CO2e scenario for the use of gas fueled generation as the US Market Purchases from 2007 to present and the Future Market-Unknown Source to 2018. Data for this calculation also used the Default Emission Factor Calculator, but set to emulate a gas plant for Mid-C hub energy (marginal natural gas = 0.400 tonnes CO2e/MWh). The CO2e emissions shown in this graph does not meet the amount prescribed by the BC Reporting Regulation. FBC does not have the requested detailed combined-cycle gas generator emission data but believes the Western Climate Initiative marginal natural gas number is a reasonable and reliable number to use for the requested natural gas scenario.

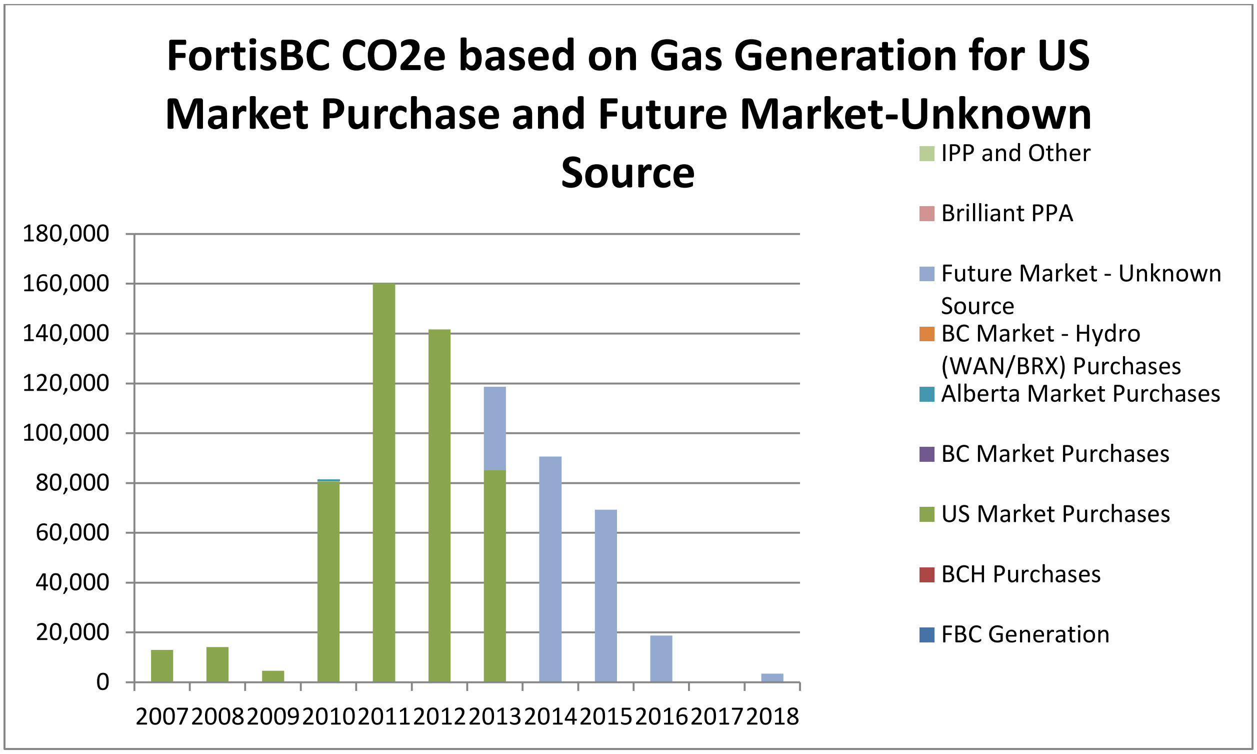
In both graphs emissions show a sharp drop in 2014 and beyond since on an operational basis, FBC expects to rely on larger volumes of BC Hydro RS3808 power to meet load. Higher emissions from 2010 to present reflect FBC's displacement of planned RS3808 power usage with more economical market purchases.

A breakdown of carbon equivalent emissions by customer class does not add any additional information since load balancing is done at the grid level and it is not possible to determine exactly which customer is served by the imported power.

Graph 1: Based on Reporting Regulation Using WCI Default Calculator for Mid-C Import Prediction



Graph 2: Gas Generation Source Recalculation as directed by the IR



For Mid-C purchases, please assume the generation source is either a combined-cycle gas generator, or renewable energy stripped of its environmental attributes (for example, by sale of its Renewable Energy Certificates) such that its emissions are equivalent to a combined-cycle gas generator. In estimating gas emissions, please include all gas emissions (including venting, flaring and fugitive) related to the final electricity production. Please provide supporting detail and describe all assumptions used.

230.1.2.1 Please discuss the appropriateness of the assumptions made above with regard to Mid-C energy purchases.

Response:

FBC believes that as described in BCUC 1.230.1.2 the use of the Western Climate Initiative Average Emission Factor Calculator as prescribed by the BC Reporting Regulations is the appropriate measure to use. Please also refer to the response to BCSEA IR 1.3.6 for further information on the composition of the Mid-C market.

230.1.3 Based on the above analysis, does FBC consider that it has complied with government expectations on BC gas emissions reduction as outlined in the Energy Plan? Please explain why/why not.

Response:

FortisBC is complying with the BC government expectations on BC Greenhouse Gas (GHG) emissions. FortisBC follows the GHG electric import reporting requirements as specified by the Reporting Regulation under the Greenhouse Gas Reduction (Cap and Trade) Act. The CAP and Trade Legislation establishes accurate reporting and appropriate action.

From the 2007 **BC Energy Plan**, Policy Action Items 18, 19 and 20 apply to FBC in regards to GHG:

18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.

230.2 Does FBC consider it should aim to reduce its expected increase in demand for electricity by the year 2020 by at least 66 percent? Please explain why/why not.

Response:

FBC believes it is fulfilling the initial part of the Clean Energy Act 2. (b) energy objective “to take demand-side measures and to conserve energy”.

The subsequent phrase in that paragraph, referencing the 66% reduction, is directed at the authority (BC Hydro) and does not apply to FBC.

230.2.1 Please provide a table showing what percentage of FBC's forecast growth in electricity consumption is expected to be met by DSM programs over the PBR period. Please provide supporting data and state all assumptions used.

Response:

The following table shows the percentage of FBC's forecast growth in electricity consumption expected to be met by DSM programs on a before loss basis. The relatively high number in 2014 has to do with the way we attribute DSM savings each year (please refer to the response to BUCU IR 1.80.1 for details).

	Forecast Incremental DSM Savings	Net Incremental Load Growth	Percent DSM Offset
2014	20,740	46,566	45%
2015	11,635	33,376	35%
2016	11,556	32,892	35%
2017	11,456	30,121	38%
2018	11,314	36,940	31%
Total	**66,702**	**179,895**	**37%**

230.3 When evaluating alternative DSM programs, does FBC give additional emphasis to DSM programs which support economic development, the creation of jobs, and the development of first nation and rural communities? If yes, please explain how.

Response:

No, FBC does not consider economic development and the creation of jobs when evaluating alternative programs.

230.4 Does FBC consider that its proposed DSM plan adequately supports the BC energy objective to "to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency..." Please explain why/why not.

Response:

FBC believes its long term support of commercially available technologies, e.g. heat pumps, will spur manufacturers to bring even more efficient models to market to attract incentives. Also the Company will continue to support pilot projects of emerging technologies, for example 200 Watt LED floodlights that replaced 1000 Watt conventional outdoor lights at a Kelowna dealership.

231.0 Reference: Overcoming Market Barriers, American Council for an Energy Efficient Economy, 2013, Executive Summary, pp. 6, [28]; Exhibit A2-10 Aligning Utility Incentives 2007[29], p. 1-3; DSM Incentives in Canada, Pembina Institute, 2004, p. 9[30]; Exhibit B-1-1, Appendix H, pp. 10, 11

Existing DSM Incentives

The Executive Summary of an American Council for an Energy-Efficient Economy March 2013 paper titled "Overcoming Market Barriers and Using Market Forces to Advance Energy Efficiency" states on pages 6 and 7:

> "Utility regulatory reform: ...In addition to serving the public interest, IOUs [Investor-owned utilities] have a fiduciary obligation to try to earn a profitable return on shareholder investments...investment in energy efficiency raise financial concerns for IOUs...No single policy mechanism can adequately remove the existing biases against utility investment in energy efficiency. However, several policies, when used in combination, can properly align financial incentives to remove the major market barriers to energy efficiency. These include cost recovery, decoupling, and providing shareholder incentives." (pp. 6, 7)

"Aligning Utility Incentives with Investment in Energy Efficiency" (2007) paper (Exhibit A2-10) includes a table (Table 1-1) titled 'Utility Financial Concerns' on page 1-3, which identifies the potential impact of DSM o the utility shareholder and potential solutions.

Pembina Institute August 2004 paper titled "Demand Side Management Incentives in Canada" states on page 9: "Two of BC's utilities, Terasen (gas) and FortisBC (formally Aquila Networks Canada, electric), are currently operating under a PBR that includes DSM financial mechanisms and incentives. Targets are set for DSM savings and, if the utility exceeds these targets, it receives credit for a percent of total savings in its next rate decision. Both utilities are allowed to amortize DSM program costs over a multi-year period that provides a further incentive to operate DSM programs."

FBC states in the Application: "...FBC requires the flexibility to be able to adjust to new information, program results and opportunities through the test period without the need for a full Commission review." (Appendix H, pp. 10, 11)

[28] http://www.aceee.org/research-report/e136

[29] Aligning Utility Incentives with Investment in Energy Efficiency, A resource of the National Action Plan for Energy Efficiency, November 2007

[30] http://www.pembina.org/pub/174

231.1 Does FBC agree that the objective of DSM could be defined as "The use of less energy to provide the same or an improved level of service to the energy consumer in an economically efficient way?" If no, please explain why not.

Response:

The quote provides a ready definition of energy-efficiency, which is but one form of DSM. Other DSM forms or objectives may include conservation, demand response, load shifting, fuel switching and load building.

For FBC, the PowerSense program encompasses not only energy efficiency, which can be described as "the use of less energy to provide the same or an improved level of service" but also conservation, which can be described as reducing or going without a level of service in order to reduce energy use". The distinction can be made as follows: upgrading a furnace from a standard model (resistance heat) to a heat pump model constitutes energy efficiency, while putting on a sweater and turning down the heat constitutes conservation.

231.2 Please add three additional columns to table 1-1 from the "Aligning Utility Incentives with Investment in Energy Efficiency" (2007) paper to identify and describe which of the potential solutions were/are being used to address potential FBC DSM related utility financial concerns (i) in 2004, (ii) currently, and (iii) as proposed in the 2014-2018 PBR application.

Response:

The relevant financial mechanisms employed by FortisBC are checked below.

In the table below the symbol, a checkmark '√' is used to identify which Potential Impact issues addressed and solutions have been used. 'n/a' is used in the table to indicate which solutions have not been applied. The BCUC has approved FBC to include DSM costs in a Rate Base deferral account which allows the utility to earn a return on its investment and to recover the expenditures by allowing the amortization expense to be included in the utility's revenue requirements.

Utility Financial Concerns

Potential Impact	Potential Solutions	2004	2012-13	2014-18
Energy efficiency expenditures adversely impact utility cash flow and earnings if not recovered in a timely manner.	• Recovery through general rate case • EE cost recovery surcharges • System benefits charge	√ n/a n/a	√ n/a n/a	√ n/a n/a
Energy efficiency will reduce electricity or gas sales and revenues and potentially lead to under-recovery of fixed costs.	• Lost revenue adjustment mechanisms that allow recovery of revenue to cover fixed costs • Decoupling mechanisms that sever the link between sales and margin or fixed-cost revenues • Straight fixed-variable (SFV) rate design (allocate fixed costs to fixed charges)	n/a √ √*	n/a √ √*	n/a √ √*
Supply-side investments generate substantial returns for investor-owned utilities. Typically, energy efficiency investments do not earn a return and are, therefore, less financially attractive.	• Capitalize efficiency program costs and include in rate base • Performance incentives that reward utilities for superior performance in delivering energy efficiency	√ √	√ n/a	√ n/a

** A portion of fixed costs are allocated to a fixed charge on customer bills.*

231.3 Please describe the current impact on the FBC shareholder earnings if annual DSM kWh energy savings exceed forecast while DSM spend remains the same (i.e. DSM c/kWh cost of energy savings decreases) and vice versa.

Response:

For the purpose of rate setting, shareholder earnings are a function of Rate Base, capital structure and allowed ROE (Return on Equity). DSM expenditures are a component of rate base (deferred charges).

In the first case (energy savings exceeds forecast but expenditures are the same as forecast), there is no impact on shareholder earnings. Rate Base is unchanged from that used to set rates because DSM expenditures are the same as forecast. Any variance in net income (changes to sales load, revenue and power purchase expense due to the increased energy savings) would be adjusted by way of the Revenue Variance and Power Purchase Expense Variance Deferral Accounts and would not impact shareholder earnings.

In the second case (energy savings equal forecast but DSM expenditures exceed forecast), there would be a shareholder impact in the current year, because the financing costs (interest expense and cost of equity) provided in revenue requirements (based on the forecast DSM expenditures) would be lower than required to finance the higher expenditures. As the deferred charge component of rate base is reforecast each year for rate setting, there would be no ongoing earnings impact. In this case, sales load, revenue and power purchase are unchanged.

231.3.1 Please describe the effect of the scenario above under (i) the PBR mechanism in place in 2004 and (ii) the PBR mechanism proposed for 2014-2018.

Response:

There are three factors relevant to the comparison of the scenarios identified in BCUC IR 1.231.3.

First, with respect to the DSM program expenditures, there is no difference in treatment in 2014 as compared to 2004.

Second, the impact of changes to sales load and power purchase expense differed in 2004 as the current Revenue Variance and Power Purchase Variance Deferral Accounts were not in place. Therefore any change in net income resulting from the higher energy savings in the first scenario would impact shareholder earnings in the current year.

Third, in 2004 there existed a DSM incentive which was based on improving the "net" benefits, by sector, compared to a 3-year rolling baseline. If savings exceeded target, the Company was eligible to earn an incentive to be added to rate base, resulting in a shareholder benefit aimed at

The incentive rates varied, depending on a performance factor, from a -6% penalty to + 6% incentive applied to the sector net benefits amount.

For example the 2011 DSM incentive amount was $109 thousand. The scenario effect is non-linear, e.g. a 10% increase in energy savings i.e. benefits increases the DSM incentive by $11 thousand, whereas a 25% increase in benefits adds $92 thousand to the original incentive amount.

231.4 Does FBC consider that, in order to move to a more light handed regulatory regime for DSM (for example, that would allow FBC to develop new DSM programs without Commission approval), it is important that (i) proper utility incentives are in place to provide economically efficient DSM, and (ii) appropriate checks/balances are in place such that ratepayers and the regulator have confidence in the DSM results reported? Please explain why/why not.

Response:

It is not clear to FBC what is meant by a "light handed regulatory regime for DSM". FortisBC has consistently delivered superior results from its PowerSense DSM program, with average expenditures at 94% of budget and savings at 107% of plan over the past 5 years.

The regulator and customers can take comfort in past performance, and they can be reassured by the comprehensive and independent EM&V framework described in this application and further detailed in the responses to BCUC IRs 1.233.1 and 1.233.2.

231.4.1 Does FBC consider that the existing DSM organizational structure and shareholder incentive mechanism supports a move to a more light-handed regulatory regime? Please explain why/why not.

Response:

If the reference to a more light-handed regulatory regime is referring to the FBC's request to be able to launch new programs without preapproval from the Commission as stated on page 11 Appendix H in Exhibit B-1-1, then, yes, the FBC believes the existing structure and mechanisms support this request. FortisBC also notes a maximum transfer of 25 percent of the budget amount from one existing program area or sector to another existing program area or sector does not require prior approval of the Commission per Order G-110-12.

Please refer to the response to BCUC IR 1.231.4.

231.4.2 Does FBC support a review of the existing DSM organizational structure and shareholder incentive mechanisms? Please explain why/why not. If yes, please suggest a recommended approach.

Response:

No, FBC does not support a review. As noted in the response to BCUC IR 1.231.4, it is the view of the Company that the DSM framework, including the organizational structure and shareholder financial mechanisms, are understood and are functioning well. The Company does not believe these matters need to be reviewed given that they are well established.

232.0 Reference: Exhibit B-1, Section A, p. 1; Exhibit B-1-1, Appendix H, pp. 18, 19; Exhibit A2-10 Aligning Utility Incentives, pp. ES-3, 6-1, 6-2;

DSM Performance Incentives

FBC states on page 1 of its Application: "FBC's primary objectives for its PBR Plan are: (1) To reinforce FBC's productivity improvement culture...(2) to create an efficient regulatory process..."

FBC states in Appendix H "FBC seeks approval to increase its DSM amortization period from ten to fifteen years..." (p. 19) and "the weighted average measure life of 15.9 years..." (p. 18)

"Aligning Utility Incentives with Investment in Energy Efficiency" (2007) paper (Exhibit A2-10) states on page ES-3:[31]

> "Under traditional regulation, investor-owned utilities earn returns on capital invested in generation, transmission, and distribution. Unless given the opportunity to profit from the energy efficiency investment that is intended to substitute for this capital investment, there is a clear financial incentive to prefer investment in supply-side assets...The three major types of performance mechanisms have been most prevalent include: Performance target incentives, shared savings incentives, Rate of return adders."

Pages 6-1 to 6-2 of the above report also include a summary of performance incentive mechanisms used in other jurisdictions.

232.1 Please describe the mechanism currently used to reduce or eliminate incentives for FBC to prefer supply-side investments over DSM investments.

Response:

FBC has proposed a 15 year amortization period in the 2014-2018 PBR Application, to better match costs and benefits (and also matches BC Hydro's amortization period).

It should be further noted that the *Utilities Commission Act*, in clause 60 (1) (b) (ii) states that in setting a rate under the Act, the Commission must "provide to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demand…" It is the view of the Company that the currently approved financial treatment for DSM expenditures, along with the proposed amortization period change to 15-years, provides such a fair and reasonable return.

[31] http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf

It is the view of the Company that the currently approved financial treatment for DSM expenditures (refer to the response to BCUC IR 1.231.2) provides a fair and reasonable return and provides for the same consideration of supply-side investments as DSM investments.

232.1.1 Please explain why FBC has not proposed a performance based incentive mechanism for DSM as part of its PBR Application. In the response please describe the advantages and disadvantages of moving to a performance based incentive mechanism for DSM.

Response:

The Company has not proposed returning to a performance-based incentive mechanism for DSM activity in this proceeding because it believes that the current mechanism (refer to the response to BCUC IR 1.231.2) is working well in that there are no dis-incentives to FortisBC pursuing DSM activity under the current mechanism.

Any perceived advantages and disadvantages of DSM performance-based incentive mechanisms would be entirely dependent on how the incentive is structured, and whether the incented utility behaviour is considered beneficial.

For example, an incentive mechanism might result in the utility favouring DSM measures with higher benefit/cost ratios. While this might result in better financial performance, customers that wish to participate in the lower benefit/cost ratio programs may be harmed.

232.2 Please explain the purpose of the current approach of capitalizing and amortizing DSM expenditures as it relates to (i) matching costs with benefits, and (ii) addressing any disincentive for FBC to invest in DSM compared to supply side resources.

Response:

The current approach of capitalizing and amortizing DSM expenditures achieves the objectives raised in points (i) and (ii) in the question above.

For item (i), the concept of matching costs and benefits is a key accounting principle that is applied to capital expenditures by depreciating capital assets over their useful lives. With respect to utility operation's capital assets (i.e. supply side resources) are employed in providing benefits (i.e. electricity service) and the asset costs are recovered in rates over time through depreciation expense (as well as a return on rate base and taxes) for the time period the assets are in service. DSM expenditures (i.e. costs) produce reductions in electricity consumption (the benefits) which persist over a period of time (referred to as the measure life). Reductions in electricity consumption from DSM program participants allow the utility to avoid having to acquire new electricity supply and avoid having to build system capacity that would otherwise be needed if the DSM programs had not been undertaken. In the absence of a Commission approval to defer and amortize DSM spending, the expenditures would be accounted for as current period expenses, just like other O&M expenses. If this was the case this would mean that DSM costs would be recovered from ratepayers in a single year while the associated benefits would occur over a number of years following. The mismatch of costs and benefits that would occur if DSM spending was not deferred and amortized is referred to as inter-generational inequity. Full matching of costs and benefits will occur when the amortization period for DSM expenditures is equal to the measure life. The weighted average measure life of 15.9 years noted in Appendix H, page 18 and the question preamble is the theoretical underpinning for increasing the amortization period from the current 10 year period to the applied-for 15 year period.

Capitalizing (or deferring) and amortizing DSM expenditures (Item (ii) in the question) also addresses any disincentive that FBC would have to invest in DSM compared to supply side resources. By this treatment, DSM expenditures are included in utility rate base and attract the same return on rate base that supply side assets would have as they are installed and added to rate base, and depreciated over their service lives. The existing regulatory accounting treatment for DSM expenditures also meets the requirements of section 60 (1) (b) (ii) of the UCA which requires the Commission to ensure that the utility's rates

> *"provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands,"*

232.2.1 Please provide a breakdown of Table H-6 in the Appendix H of the Application to show the estimated measure life for each DSM program, and the key assumptions made in arriving at these estimates.

Response:

The Effective Measure Life (EML) estimates were provided by EES Consulting in conjunction with the 2013 Conservation Potential Update. EES relied on published measure data from three principal sources: OPA, BPA and BC Hydro.

1	Program Area	EML (years)
2	**Residential Programs**	**18.0**
3	Building Envelope	25
4	Insulation - R0 Base	25
5	Insulation - R19 Base	25
6	HVAC - Draftproofing	25
7	Heat Pumps	20
8	Heat Pump Upgrade - Air Source	20
9	New Home	30
10	EnerGuide80	30
11	Lighting	12
12	Lighting - Screw-in	11
13	Lighting - Hard-wired	15
14	Water Heating	11
15	Water Heater - HPWH	15
16	Other Water Heating	11
17	Low Income & Rentals	12
18	Energy Saving Kits	7
19	Direct Install - Basic	19
20	Direct Install - Advanced	19
21	Direct Install - Lighting	15
22	**General Service Programs**	**14.7**
23	Lighting	11
24	Existing - all but metal halide	11
25	Existing - metal halide	11
26	New	15
27	Controls	15
28	BIP	18
29	Whole Building New	30
30	HVAC New	19
31	Weatherization	20
32	Refrigeration	10

1	Program Area	EML (years)
33	Irrigation	10
34	All	10
35	**Industrial Programs**	**9.9**
36	Other	10
37	**Program Totals**	**15.9**

232.2.1.1 Has the persistence of savings estimate used to support the amortization period been reviewed and approved by an independent consultant? If yes, please describe the process used and summarise the results. If no, please explain the process used to obtain these estimates.

Response:

The EML (Effective Measure Life) figures used to create Table H-6 were provided by EES Consulting, an independent consultant that prepared FBC's 2010 Conservation and Demand Potential Review and the current 2013 CDPR Update. EES referenced the program measure data from three principal sources: BC Hydro's 2007 CPR, Northwest Power & Conservation Council's Sixth Power Plan, and the Ontario Power Authority measure database.

232.3 Please describe how any over or under-spend of the DSM budget by FBC will be accounted for over the PBR period.

Response:

Although the DSM expenditure levels will be pre-determined for the 5-year term of the PBR, the DSM expenditures are a deferred expenditure as opposed to a capital expenditure and thus the deferred (or rate base) balances are reforecast annually as part of the Company's annual review.

232.4 Please provide FBC's position on replacing the existing rate of return incentive with each of the following performance measures (refer Table 6-1 in "Aligning Utility Incentives with Investment in Energy Efficiency" paper):

- Share of net economic benefits up to 10 percent of total DSM spending (Arizona).
- Share of net benefits (Georgia – 15 percent, Hawaii – 5 percent).
- Management fee of 1 to 8 percent of program costs (before tax) for meeting or exceeding predetermined targets. One percent initiative is given to meet at least 70 percent of the target, 5 percent for meeting the target, and 8 percent for 130 percent of the target (Connecticut).
- Up to 2 percent added ROE on DSM investments if performance targets are met with one percent penalty otherwise (Indiana).
- 5 percent of the program costs if savings targets are met on a program-by-program basis (Kansas, Massachusetts).
- Specific share of net benefits based on cost-effectiveness test is given back to the utilities. At 150 percent of savings target, 30 percent of the conservation expenditure budget can be earned (Minnesota).

Response:

FBC does not believe a DSM regulatory incentive is necessary and has not undertaken a detailed analysis of the various DSM performance incentive mechanisms listed here.

FBC's general understanding of the DSM performance based incentive mechanisms in other jurisdictions is that they have been designed to overcome the general disincentive for utilities to pursue DSM because DSM activities in those jurisdictions are not treated on an equal footing with supply side activities, and DSM in those jurisdictions will reduce the use of utility product and utility returns. The financial treatment for DSM activity approved and adopted in BC for FBC and for other public utilities effectively addresses the disincentive to DSM expenditure found in other jurisdictions. This approved treatment is consistent with the requirements of section 60(1)(b)(ii) of the UCA, whereas the performance measures listed above are not. FBC believes the current approach in BC is appropriate and does not need to be changed.

Please refer also to the responses to BCUC IRs 1.232.1 and 1.232.1.1.

233.0 Reference: Exhibit B-1-1, Appendix H-3, DSM Monitoring and Evaluation Plan 2013-2015

Evaluation, Measurement and Verification - Independence

FBC provides its DSM Monitoring and Evaluation Plan 2013 to 2015 in Appendix H-3 of the Application.

233.1 Please provide an overview of FBC's approach to DSM evaluation, measurement and verification (EM&V). Please include in this overview: who is responsible for which tasks, their expertise and place within the organization, reviews/checks undertaken of EM&V results, and the level of independence of the reviewer.

Response:

The FBC approach to DSM evaluation, measurement and verification is described in Section 7 of Appendix H and Section 1 of the M&E Plan in attachment H-3.

FBC staff responsible for EM&V activities operate under a separate manager from those DSM staff responsible for program development and implementation i.e. delivery.

The table below summarizes the two key FBC staff responsible for Evaluation, Measurement & Verification.

DSM Monitoring & Evaluation (M&E)	Expertise & Experience	Responsibilities
Monitoring and Evaluation (M&E) Analyst	• B. Science, Chemistry Major with Environmental Option, McGill • M. Resource Management, SFU • Planning Institute of British Columbia (Candidate Member) **Completion of the following DSM evaluation related training courses:** • Association of Energy Services Professionals - Principles of Evaluation, Measurement & Verification (EM&V)	• Initiates and schedules evaluation studies. • Provides direction for Evaluation studies. • Qualifies consultant selection, and writes RFP scope of work. • Reviews evaluation plans from consultants. • Gathers and manages the use of consumption and other data for evaluation purposes. • Ensures adherence to industry standards and protocols. • Participates in the review of inputs (NTGR) to the cost effectiveness analysis. • Ensures the integrity and reliability of the Energy Management (EM) database.

DSM Measurement & Verification (M&V)	Expertise & Experience	Responsibilities
PowerSense Engineer	• B. Applied Sc. (Environmental Engineering), Waterloo • M. Resource Management, SFU • Assoc. Professional Engineers & Geoscientists of BC (EIT) • Consultant Navius Research (formerly M.K. Jaccard and Associates) • Contractor to Canadian Industrial Energy End-Use Data and Analysis Centre (CIEEDAC) **Completion of the following DSM evaluation related training courses:** • Certified Measurement and Verification Professional (CMVP) training course	• Develop and complete M&V plans • Measurement equipment specification, selection and monitoring • Data management and quality review • Data analysis and reporting • Site visits and project scoping • Review of technical reports and information • Review of inputs to the cost effectiveness analysis

The M&E Analyst and PowerSense Engineer report directly to the Manager, PowerSense Programs, who approves evaluation plans, budgets and reports, and oversees the implementation of any changes to cost effectiveness test inputs that result from evaluation activities.

233.2 Does FBC consider that there is a potential conflict of interest in a utility both undertaking DSM activities and being responsible for DSM EM&V? Please explain why/why not.

<u>Response:</u>

No, FBC does not consider that there is a potential conflict of interest. FBC's EM&V activities are appropriately segregated to avoid any such conflict of interest situation that could arise between the development and delivery of DSM programs and the evaluation of those programs within the utility. This has been achieved by way of its organizational structure, i.e. different staff involved in program development and analysis acting in an ethical manner in accordance with the Companies' Business Ethics Policy.

The use of independent consultants to undertake comprehensive M&E reports further avoids potential conflict of interest. FBC's reliance on independent third party consultants to conduct the majority of the M&E activities is a common industry practice. These consultants are selected by an RFP purchasing process independent of the DSM Program Managers. They are chosen based on a combination of their relevant experience, capacity, previous work history and pricing. Once selected, the consultant(s) then develop a detailed evaluation plan based on the scope of work provided by the Evaluation staff. The consultant typically undertakes any necessary market research (for example with participants, and relevant trade allies), conducts the process and savings impact analysis and prepares a report. The independent third party consultants adhere to the industry guidelines, engineering calculations and methodologies, survey reporting analysis and the industry code of ethics for all evaluation activities conducted.

The EM&V activities are managed and conducted by professionally qualified staff independent from the program managers responsible for designing and delivering DSM programs. Evaluation staff ensure that evaluation requirements are defined at the program design stage and set evaluation requirements independent of the Program Managers for which studies may be successfully conducted. Such segregation enables the development and completion of unbiased EM&V reports which then serve as a valuable tool for which to make enhancements and changes to future DSM program delivery. Evaluation studies are conducted on a program by program basis and adhere to sections 2.2 "Evaluation Objectives" and 2.3 "Evaluation Principles" in the draft EM&V Framework, which has been filed in response to BCUC IR 1.233.3.

The EM&V framework was developed by reviewing industry guidelines and common practices for EM&V activities. One of the FBC's evaluation principles contained in the Framework is that of providing transparency both internal and external to the FBC with respect to EM&V activities, e.g. the 3rd party consultant's M&E reports are filed with the BCUC on request by the Commission and/or interveners.

Additionally the regulatory review process by which the FBC receives approval for their DSM funding provides additional transparency for external stakeholders.

233.3 When does Fortis BC plan to have the EM&V Framework finalized? If it has been finalized, or is available in draft form, please provide a copy.

Response:

Please refer to Attachment 233.3 for the EM&V Framework – Final Draft.

FBC has not yet finalized the EM&V Framework. FBC and the FEU consider the Framework to be largely complete and plan to finalize it during the fall of 2013. At this time there have been no changes to the draft version of the Framework filed as an attachment, and FBC is not anticipating significant changes prior to finalizing. Once finalized, the EM&V Framework will be updated from time to time in consultation with industry and stakeholders as industry practices evolve and are adopted by the Companies.

233.3.1 How does FBC plan to incorporate the EM&V Framework into its five-year DSM plan, and what process does FBC propose for regulatory review of the EM&V framework if it is not subjected to regulatory review within this Application?

Response:

The draft EM&V Framework was used as a reference document, i.e. technical specification that informed the scope of work of the consultant who prepared the 2013-15 DSM Plan filed in Appendix H3.

The draft EM&V framework document has been filed in response to BCUC IR 1.233.3 above.

233.4 Please confirm that the EM&V Framework is a separate document from the M&E Plan filed as Appendix H-3 of the Application.

Response:

Confirmed.

234.0 Reference: Exhibit B-1-1, Section 7, p. 16; Appendix H3

Evaluation, Measurement and Verification

FBC states on page 16 that: "FBC considers Evaluation, Measurement and Verification (EM&V) to be an important aspect of the overall DSM program lifecycle. Over time the Company will evaluate all programs, with comprehensive, impact, process and/or market reviews at appropriate times in the program life cycles."

234.1 Please describe the overall lifecycle of a typical DSM program.

Response:

A DSM program generally results from a Conservation Potential Review, wherein a measure or group of similar measures identify an economic energy savings opportunity. The next stage is program development, in which the market opportunity is assessed and barriers (measure availability, incremental cost & affordability, installation capacity for example) are addressed in the program design. The program may enter a pilot project phase which allows the measure(s) to be tested, and the program attributes (savings, incentive amount etc.) to be confirmed. Next the program is officially launched into market, and later a process review may be undertaken to fine-tune the program's application process, which can involve measure savings verification. The program is tracked with internal monthly reports, and periodic (year-end) reports to the BCUC and stakeholders. Once the program is mature it will undergo a comprehensive M&E review on approximately a 3-year cycle. The M&E review may identify issues, again process or (say) high free-ridership rates that prompt program revisions. Eventually the program is subject to closure because the achievable potential has been largely taken-up, or market transformation has occurred (the energy-efficient measures have been adopted as the new baseline).

234.2 Please describe the activities that fall under "evaluation", "measurement" and "verification", who is best placed to carry such activities and why.

Response:

FBC assumes that BCUC refers to Appendix H, not Appendix H3.

As described in the response to BCUC IR 1.235.1, Evaluation, Measurement and Verification (EM&V) is an encompassing term that is used to describe measurement and verification as well as monitoring and evaluation activities. The response to BCUC IR 1.235.5 indicates that Measurement & Verification is a single term that represents the same group of activities. The table below provides information relating to both evaluation and measurement and verification.

Evaluation, Measurement and Verification (EM&V)	Activities	Personnel responsible for activities	Rationale
Evaluation	Applied at the program level: - impact, process, and market reviews of programs, - examine projects approved under a DSM program over the program's study interval (typically two to three years).	Monitoring & Evaluation Analyst and/or consultants	These personnel are responsible for evaluation of programs.
Measurement & Verification (M&V)	Applied at the project level: - determine actual savings associated with individual projects that are submitted by customers for incentive consideration.	PowerSense Engineer, FBC technical advisors, consultants, and/or equipment vendors	These personnel are responsible for determining savings associated with DSM projects.

234.3 Please explain the respective objectives of an impact, process and market reviews and the differences between them. Would these reviews fall exclusively under the category of "evaluation" activities?

Response:

FBC assumes that BCUC refers to Appendix H, not Appendix H3.

Confirmed, these reviews fall under the category of "evaluation" activities.

Impact reviews or evaluations measure the energy savings achieved by a DSM program. Objectives of impact evaluations include assessing the realization rate (e.g., level of savings achieved) for the projects in the program and estimating free-rider and spill-over (market) effects to determine net savings impacts.

The purpose of a process evaluation is to examine the effectiveness of program delivery. Objectives of process evaluations include improving program implementation and program delivery as well as ensuring high satisfaction levels among customers, trade allies and other program participants.

Market reviews or evaluations determine a DSM program's effectiveness at increasing the market penetration of an efficient technology or measure. Objectives for market evaluations include measuring increases in market penetration of energy efficient technologies and assessing the share of measures attributable to the program.

234.3.1 Please clarify if FBC intends to evaluate all DSM programs from an impact, process and market perspectives. If not, why not. If so, please explain how FBC intends to carry market reviews of its DSM programs when its DSM Monitoring and Evaluation Plan 2013-2015 does not describe nor include activities related to market reviews for residential, commercial and industrial DSM programs.

Response:

As described in the 2013-15 M&E Plan in Appendix H3, FBC intends to evaluate all DSM programs from an impact, process and market perspective.

The market perspective will, for the most part, be informed by interviewing market actors such as trade allies (contractors, wholesalers, retailers etc.). Due to its limited service area FBC does not attempt to undertake market transformation studies which necessarily encompass a provincial, or Western Canadian regional perspective.

235.0 Reference: Exhibit B-1-1, Section 7.1, p. 16; Appendix H-3

Monitoring and Evaluation Plan

In section 7.1, FBC uses the terms "M&E activities", "P&E expenditures" and "EM&V activities".

235.1 Please clarify what each acronym stands for, as well as each letter within each acronym. Also clarify whether FBC uses a term interchangeably with another, whether there is overlap between the meaning of terms or not. Please also clarify the relationship between each activity, in particular any hierarchy or sequencing of activities that govern these activities.

Response:

The following response provides clarification to the terms EM&V, M&E, P&E, and adds an explanation of a related term M&V.

The acronyms describe, and put into context, the evaluation, measurement, and verification of FBC's DSM programs:

- M&V = Measurement and Verification
- M&E = Monitoring and Evaluation
- EM&V = Evaluation, Measurement and Verification
- P&E = Planning and Evaluation

There is some overlap in the meaning of these terms, as described below. The terms are arranged in ascending order with the subservient activities incorporated into the superior components that follow. The following text attempts to differentiate the four components.

Measurement and Verification (M&V) is typically applied at the project level, largely directed at individual rebate applications. In essence, it provides the requisite analysis of energy savings for individual projects that are submitted by customers for incentive consideration.

Monitoring and Evaluation (M&E) activities include program reviews that examine projects approved under a DSM program over the program's study interval (typically two to three years). The impact analysis aspect of a comprehensive M&E study includes assessing the realization rate (e.g., level of savings achieved) for the projects in the program. The realization rate provides feedback to the M&V process to confirm that the whether M&V procedures are rigorous – indicated by high realization rates; or the need for tighter M&V procedures – if realization rates are low.

Evaluation, Measurement and Verification (EM&V) is an encompassing term that is used to describe measurement and verification as well as monitoring and evaluation activities.

Planning & Evaluation (P&E) expenditures represent a budget line item that incorporates all EM&V activities described beforehand, and DSM planning activities. DSM planning includes commissioning studies (End-use surveys, Conservation Potential Reviews etc.), preparing DSM plans and budgets, filing DSM reports (e.g. Semi-Annual DSM Report to the BCUC), and fulfilling other regulatory requirements.

FBC states on page 16 that: "Attachment H3 contains the Company's 3 Year Evaluation Plan, covering the 2013 to 2015 period for its M&E activities, including evaluations for process, impact, and communications, as well as measurement and verification activities for its current and planned DSM programs."

235.2 In light of FBC's request for approval of DSM expenditures for the period 2014-2018, please explain why FBC's Evaluation Plan is only a three-year plan covering the period ending in 2015.

Response:

The M&E Plan term reflects past practice, regardless of varying test periods, and incorporates a complete M&E program cycle i.e. all programs should be evaluated over the three year term.

A subsequent Evaluation Plan, to cover the 2016-18 period, will be created prior to the 2015 year-end. It will be compliant with the EM&V Framework, including any revisions thereto, and the scope will include impact, process and market perspectives of all DSM programs deployed. The 2016-18 M&E Plan will be filed in advance of the PBR annual review in the latter part of 2015.

235.3 Please clarify which communications activities are described in the DSM Monitoring and Evaluation Plan. Who is intended to carry such activities with whose audience in mind?

Response:

The scope of comprehensive M&E program studies includes the consultant reviewing the programs' communications activities (tactics, channels, market segmentation etc.) to customers and trade allies that raise public awareness, address barriers and draw participants to the program in question.

235.4 Please clarify which measurement activities are described in the DSM Monitoring and Evaluation Plan for the current and planned DSM programs.

Response:

As described in the response to BCUC IR 1.235.1 above, M&V is done to verify energy savings for individual projects that are submitted by customers for incentive consideration. In particular, measurement activities include the measurement of energy use before and after a project to calculate energy savings. Measurement activities are undertaken by FBC technical advisors, consultants, or equipment vendors and measure the energy usage of individual processes, entire facilities, or can be a calibrated simulation model.

235.5 Please clarify which verification activities are described in the DSM Monitoring and Evaluation Plan for the current and planned DSM programs.

Response:

Please refer to the response to BCUC IR 1.235.4 as M&V is a single term that represents the same group of activities.

FBC further states on page 16 that: "Overall planning & evaluation (P&E) expenditures reported in Section 5.1 include costs for EM&V activities. The total proposed expenditure for program evaluation activities to be conducted from 2013 to 2015 is approximately $815 thousand. The proposed budget aligns with the Company's EM&V

Framework and industry general practice14 for budget spending on M&E activities, representing 7.9 percent of the Company's total DSM portfolio expenditure."

Footnote 14 on page 16 states: "California Evaluation Framework. June 2004. TecMarket Works."

On page 131 of the Commission's Decision in the FBC's 2012-2013 RRA and ISP Decision, it is noted that:

"The 2004 California Evaluation Framework, a seminal document for DSM evaluation, references a spending range of 2-10 percent of overall DSM budget spending on DSM evaluation among utilities in North America, with the average spending being 4 percent."

235.6 Please explain how Fortis BC calculated that its proposed M&E budget represents 7.9 percent of its total DSM portfolio expenditures.

Response:

The 2014 M&E plan budget of $236 thousand divided by the DSM plan budget of $3,001 thousand, yields 7.9 per cent.

235.7 Please provide a summary of actual/planned spend on EM&V activities, in dollar terms and as a percentage of the overall DSM budget, for the last two years and for each year of the PBR period.

Response:

The actual/plan expenditures on EM&V activities are as follows:

2012 Actual	2013 Approved	2014 Plan	2015 Plan	2016 Plan	2017 Plan	2018 Plan
$ 356	$ 396	$ 296	$ 303	$ 311	$ 319	$ 326
4.2%	4.3%	9.8%	9.8%	10.2%	10.3%	10.4%

235.7.1 Does FBC consider that the EM&V spend as a proportion of total DSM spend is consistent with that of other DSM providers? Please explain why/why not.

Response:

In keeping with general industry practice and in alignment with the EM&V Framework, FBC plans EM&V budgets to generally fit in the spending range reported in the California Framework referenced.

The Company believes the EM&V expenditure proportion of approximately 10% is consistent with other DSM providers, and appropriate for the level of DSM spending proposed.

FBC defines EM&V spending to include the annual cost of activities and staffing related to Evaluation, Measurement and Verification of DSM Programs. The table below shows EM&V spending as a percentage of total DSM spending for FBC and a number of other utilities in 2012. FBC's EM&V spend in 2012 was 5% of portfolio expenditure, which equals the average of the sample group shown. The sample group shows an EM&V range of 1-10%, with an outlier at 23%.

Utility	Evaluation Spending	DSM Portfolio Spending	% spending on EM&V for 2012
FortisBC - Electric	$ 356,413	$ 7,300,487	5%
FortisBC - Natural Gas	$ 469,000	$ 23,760,000	2%
BC Hydro	$ 4,959,756	$ 175,250,000	3%
Consumers Energy	$ 2,506,196	$ 67,369,007	4%
Pacific Power (CA)	$ 198,519	$ 2,088,986	10%
Pacific Power (WA)	$ 751,468	$ 10,058,439	7%
Rocky Mountain Power (ID)	$ 796,620	$ 3,415,752	23%
Rocky Mountain Power (WY)	$ 92,046	$ 3,771,271	2%
Xcel MN	$ 1,830,599	$ 89,403,232	2%
APS	$ 1,929,312	$ 73,498,198	3%
PG&E	$ 21,163,063	$ 418,706,251	5%
SCE *	$ 13,653,593	$ 301,286,112	5%
SDG&E *	$ 5,684,012	$ 232,741,602	2%
SoCalGas *	$ 5,590,493	$ 188,514,346	3%
Xcel CO	$ 514,379	$ 79,441,169	1%
		Average % Spending on EM&V for 2012	**5%**

235.8 If the total proposed spending for EM&V activities for the period 2013-2015 is about $815 thousand, please confirm that the proposed annual expenditure for EM&V is approximately $271.7 thousand per year (i.e., $815,000/3).

Response:

Not confirmed. Please refer to the response to BCUC IR 1.235.7 for the actual/plan EM&V expenditure schedule.

235.8.1 If so, what does the "Planning and Evaluation" line, valued at $492 thousand for the year 2014, include in addition to the $271.7 thousand for EM&V activities?

Response:

The $271.7 thousand is an incorrect assumption – please refer to the response to BCUC IR 1.235.7. The correct EM&V figure for 2014 is $296 thousand.

The difference ($492 – $296 = $196 thousand) covers the costs required for DSM planning, technical resources (internal staff & consulting) and to manage the Planning and Evaluation functions.

On page 21 of the DSM Monitoring and Evaluation Plan 2013-2015, Johnson Consulting Group (Johnson) states: "FBC currently budgets approximately $370,000 per annum for Monitoring and Evaluation, including internal staffing and external comprehensive M&E reports. The proposed additional process evaluation activities will incrementally increase the total budget. The estimated range of the increased costs is between $30,237 and $55,417 per annum. Therefore the resulting total budget requirements will be between $400,000 and $425,000 per annum."

235.9 Please reconcile the difference between FBC's proposed annual expenditure for EM&V of $815,000 for 2013-15 and Johnson's proposed annual budget requirement of $400,000-$425,000 for M&E reports, which would total $1,200,000-$1,275,000 over the period 2013-15.

Response:

As shown in the response to BCUC IR 1.235.7, the proposed EM&V expenditures total $995 thousand (not $815 thousand as stated in the preamble) for the 2013-15 period when M&V efforts are included.

The difference between FBC's $995 thousand, and Johnson's proposed budget range, therefore totals between $205 to $280 thousand for the period.

The EM&V budget reduction brings the EM&V spending in line with the DSM program expenditure reduction, and within the California Framework spending range – at least for the 2013-15 period in question.

235.10 If the proposed M&E Plan is estimated to cost between $400,000 and $425,000 per year, while FBC is planning to spend $3,001 thousand on DSM in 2014, please confirm that the proposed budget for the M&E Plan would represent between 13.3 and 14.2 percent of FBC's overall DSM budget for 2014.

Response:

FBC has not adopted Johnson Consulting's proposed budgetary range. Please refer to the response to BCUC IR 1.235.7 for the EM&V plan expenditures.

The per cent EM&V expenditure is discussed in the response to BCUC IR 1.235.7.1

235.10.1 Would this still be aligned with industry's general practices as presented in the 2004 California Evaluation Framework? Why or why not.

Response:

Please refer to the response to BCUC IR 1.235.7.1. The proposed EM&V expenditure levels are consistent with the 2004 California Evaluation Framework.

236.0 Reference: Guide to the Demand-Side Measures Regulation, BC Ministry of Energy and Mines, p. 4[32]; Exhibit B-1-1, Appendix H, pp. 13, 14

Purpose of Total Resource Cost Test

Page 4 of the BC Ministry of Energy and Mines Guide to the Demand-Side Measures Regulation states:

"...s. 4(1.1) requires that the commission "must make determinations of cost effectiveness by applying the total resource cost test" as modified by a set of instructions...The TRC test is a cost-benefit calculation in which one of the benefits is the avoided cost of the energy saved by the DSM. In a TRC test this is typically valued at the marginal cost of that energy to the utility."

FBC states in the Application: "Amendments to the DSM Regulation in 2011 included the addition of subsection 4(1.1) allowing for the use of the MTRC for up to 10 percent of the electricity DSM portfolio ...The MTRC includes two key components: the use of BC "clean" new resource in determining avoided cost of energy of DSM, and the inclusion of non-energy benefits (NEB) to customers and the utility." (Appendix H, pp. 13, 14)

236.1 Please describe how FBC calculates both the Total Resource Cost Test (TRC) and the Modified TRC (mTRC), including the key inputs and the formula used.

Response:

TRC:

The typical inputs into a TRC Benefit/Cost ratio (BCR) calculation are as follows:

- incremental measure costs,
- benefits of energy savings, based on the avoided cost of electricity,
- amount of energy savings (kWh, kW) per measure,
- number of measures, free rider rate,
- spillover rate (if applicable),
- measure life,
- program administration costs, and the
- discount rate
- Deferred capital expenditure (DCE), a proxy for avoided incremental Transmission & Distribution costs

32 http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Documents/Guide%20to%20the%20DSM%20Regulation%20August%202012.pdf

mTRC:

- The mTRC is largely the same as TRC, except the DSM Regulation specifies that a higher LRMC, representing the value of BC "clean" new resources, and a 15% NEB (non-energy benefits) be added

FortisBC performs the TRC and mTRC tests as a benefit/cost ratio. If the ratio is above 1.0, the test is passed.

The benefits are the present value of all quantifiable benefits listed above, with energy savings valued at the appropriate avoided cost of energy and modified by any free rider or spillover rates.

Costs include the total cost of the measure (utility incentives and incremental customer costs) as well as DSM program administration costs.

236.1.1 Does FBC consider that the purpose of the TRC/mTRC could be described as identifying whether there would be a BC benefit from encouraging customers to change their investment decisions or behaviors in a way that provides similar or improved level of service from the energy consumed? Please explain why/why not.

Response:

This is not always the case. Please refer to the response to BCUC IR 1.231.1 where the various categories of DSM are discussed. DSM from conservation (for example, turning down the thermostat or air conditioner duty cycling), may have a positive TRC/mTRC but can result in a reduced level of service to the participant.

> *"The primary purpose of the TRC is to evaluate the net benefits of energy efficiency measures to the region as a whole…The TRC is useful for jurisdictions wishing to value energy efficiency as a resource not just for the utility, but for the entire region. The TRC is also useful when energy efficiency might fall through the cracks taken from the perspective of individual stakeholders, but would yield benefits on a wider regional level."* [33]

[33] page 6-6 http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

FBC concurs with this interpretation of the TRC, namely that the TRC evaluates whether or not British Columbia generally is better or worse off from DSM activity that encourages customers to change their investment decisions or behaviours.

The use of the mTRC results from a government regulation, so the Company refers back to material created by government to support stakeholders in interpreting the Demand Side Measures Regulation, such as the Guide to the Regulation referred to in the Information Request. As can be seen on page 6 of "Overview of the DSM Regulation"[34], "One of the principal components of the MTRC is the use of the price signal for a zero-emission energy supply alternative (ZEEA) as the avoided cost of energy for DSM. [T]his is FortisBC Inc's long-run marginal cost of acquiring electricity generated from clean or renewable resources in BC".

236.2 Does FBC consider that the mTRC improves the accuracy of the TRC calculation by including in the analysis (i) emission reduction benefit of DSM, and (ii) an estimate of additional non energy benefits the customer may receive from making the investment (such as comfort, improved health, reduced noise etc.)? Please explain why/why not.

Response:

FBC would not characterize the mTRC improving the accuracy of the TRC. The financial benefit of DSM relates only the avoided cost of supply and any other quantifiable financial benefits. Emissions are reduced by DSM only to the extent that the avoided marginal supply has lower emission levels than the existing supply. Non-energy benefits may result from DSM (and would be included if financially quantifiable), but as discussed in the response to BCUC IR 1.236.1.1, the customer may actually experience reduced non-energy benefits from DSM.

Finally, in the opinion of FortisBC, the DSM regulation limits the use of mTRC because it is less "accurate" than the standard TRC calculation.

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34 http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Documents/Guide%20to%20the%20DSM%20Regulation%20August%202012.pdf

236.3 Does FBC agree that increasing the FBC DSM incentive (for example from 5 percent of the product price to 100 percent of the product price) will not result in a lower TRC/mTRC result? Please explain why/why not.

Response:

FBC agrees that increasing the DSM incentive will generally not affect the TRC/mTRC result.

236.3.1 Does FBC consider that the effect described above means that the TRC/mTRC should not be used as the only measure to determine the cost effectiveness of DSM programs? If no, please explain why not.

Response:

As explained in Section 6 of Appendix H to the Application, Exhibit B-1-1, FBC considers that the appropriate way to determine the cost effectiveness of DSM programs is to apply the TRC / mTRC and Rate Impact Measure tests at the Portfolio level. It is also useful to calculate and monitor other cost effectiveness tests both at the portfolio and individual program levels (and have thus been consistently reporting a range of cost effectiveness test results in its DSM Semi-Annual Reports), but these other tests should not be applied to determine whether a program is implemented or not. Other cost effectiveness tests can provide information about the impacts of DSM programs from different perspectives. However, the benefits of DSM investments are better optimized by having a robust portfolio of programs working together to provide all customers with access to programs while achieving energy savings.

236.3.2 Does FBC consider that the TRC/mTRC is more of a pass/fail test (i.e. an initial screening tool), or does FBC consider it should maximize its TRC/mTRC portfolio results? Please explain.

Response:

FBC considers that the TRC/mTRC is a pass/fail test, but is unsure of the Commission's intended meaning about its use as an initial screening tool. There are many factors that go into deciding the programs and activities that will make up an optimal DSM portfolio, and FBC did not limit its portfolio based solely on cost effectiveness results.

At the program level, FBC seeks to design programs to optimize the TRC/mTRC results, while including considerations such as:

- fair access to programs by all customers;
- the importance of supporting activities for which energy savings cannot be attributed; and
- overhead costs such as labour, training, transportation, capacity building and consulting services that are essential for an effective DSM effort.

236.4 Does FBC agree that use of the mTRC instead of the TRC to evaluate DSM programs places no upward pressure on overall customer electricity bills provided the programs pass the Utility Cost Test? If not, please explain why.

Response:

FBC disagrees. If a program passes the Utility Cost Test, the utility revenue requirement will be reduced. However, the UCT does not measure the impact of a program on average rates (the revenue requirement divided by billable load). Therefore, it is possible to have programs pass the UCT but still be inflationary on average rates, which in turn creates "upward pressure on overall customer electricity bills".

237.0 Reference: BC Ministry of Energy and Mines Guide to the DSM Regulation, p. 4[35];

Purpose of the Utility Cost Test and Key Inputs

Page 4 of the BC Ministry of Energy and Mines Guide to the Demand-Side Measures Regulation states:

"...s. 4(1.8) allows the commission to determine (with some exceptions) that a demand-side measure that fails the UCT is not cost-effective. This subsection does not suggest that the commission must or should reach this determination, it simply empowers it to do so even if s. 4(1.1) makes a measure cost-effective under the modified TRC..."

237.1 Please identify the inputs into a Utility Cost Test (UCT) calculation, and provide an overview of the methodology used to calculate the value of these inputs.

Response:

FBC calculates the UCT test as the ratio of the total net benefits of a program, discounted by the net to gross ratio to address free riders and spillover where applicable, to the total costs for the utility over some specified time period. The benefits of the test are similar to the TRC benefits which are the net avoided electricity supply costs. The costs for the test are the total program costs incurred by the utility including the incentives paid to the customers, the marketing cost, the operational cost and evaluation costs etc.

237.1.1 What discount rate is used for the UCT calculation, and is this discount rate the same as the one used to evaluate utility supply side investments?

Response:

The DSM Plan used an 8 per cent discount rate for DSM Benefit calculations including the UCT ratio, which is consistent with the Company's past practice, i.e. the same as used to evaluate supply-side projects.

Note: the FBC 2014-18 PBR filing does not request approval of any supply side projects.

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35 http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Documents/Guide%20to%20the%20DSM%20Regulation%20August%202012.pdf

237.2 Does FBC consider that the purpose of the UCT could be described as identifying whether, once the TRC/mTRC has identified that customers are making suboptimal investment/consumption decision from a BC perspective, it would be cost effective for the utility to step in and mitigate the problem rather than supply the additional energy that would otherwise be required? Please explain why/why not.

Response:

The UCT provides an indication of the utility revenue requirement impact on an NPV basis. However, even if an energy efficiency measure decreases the revenue requirement, it may still increase average rates due to reduced billable load.

The UCT is useful in determining appropriate incentive rates and for comparing the cost of demand-side and supply-side measures.

237.2.1 Does FBC consider that, as a general rule, the higher the UCT result, the higher the benefit to FBC ratepayers overall? Please explain why/why not.

Response:

Speaking very generally, FBC would agree in theory that the higher the UCT, the more cost-effective it is for the utility to reduce demand. The perspective on the benefit or cost to FBC ratepayers overall, as British Columbians, is more optimally provided by the TRC/mTRC.

237.3 Please confirm that, unlike the TRC/mTRC, the UCT does change significantly if the utility incentive was increased from 5 percent to 100 percent of the customer's cost, and so is a useful indicator in measuring the cost effectiveness of each DSM program proposed by the utility. If unable to confirm, please explain why not.

Response:

Confirmed, the UCT is useful as a complementary measure to the governing TRC/mTRC test, as are the Rate Impact Measure and Participant Cost Test.

238.0 Reference: Estimating LRMC in the National Electricity Market, NERA, pp. 4 - 9[36]; A Comparison of the LRMC and Price of Electricity in Alberta, Alberta Market Surveillance Administrator, 2012, pp. 4-6; BC Hydro website, LRMC Components and Description[37]

LRMC: literature review

NERA December 2011 paper titled "Estimating Long Run Marginal Cost in the National Electricity Market" states on page 4:

"The key distinction between the concept of SRMC and LRMC is whether productive capacity is treated as fixed or is allowed to vary. In the context of a wholesale electricity market, the LRMC therefore includes the marginal cost of future capital that is required to provide sufficient generation capacity to meet an increase in demand."

The NERA paper also includes a comparison of two broad methodologies used to estimate the capital component of the LRMC for a market (perturbation approach and average incremental cost approach) and states that, in their opinion, the perturbation approach is the preferred approach. (pp. 5 – 9)

A December 2012 report by the Alberta Market Surveillance Administrator (MSA) titled "A Comparison of the LRMC and Price of Electricity in Alberta" identifies four approaches used to measure LRMC on pages 4 to 6. The report states the perturbation approach is most likely to yield the best LRMC estimate.

BC Hydro includes on its website a summary of its LRMC of Firm Energy Components and Description.

238.1 Please provide a definition of long-run marginal cost as used for the TRC, UCT and modified TRC.

<u>Response:</u>

Excerpt from the California Standard Practice Manual: "The benefits calculated in the Total Resource Cost Test are the avoided supply costs-- the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost...". In this filing FBC has used an LRMC which is inclusive of capacity costs, and added a Deferred Capital Expenditure factor, based on plan kW savings, to represent incremental Transmission & Distribution capital costs.

36 http://www.aemc.gov.au/Media/docs/Technical%20paper-168ea920-eb90-446d-a033-ab07edf8a8a6-0.pdf

37 http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q4/lrmc_firm_energy_components.pdf

The same LRMC definition would apply to the UCT.

For the mTRC the DSM Regulation s4.(1.1)(b)(i) states… "an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia,". Additionally s4.(1.1)(c)(ii)(A) states:… "increases by 15% the benefits of the expenditure portfolio of which the demand-side measure is a part."

238.2 Please provide FBC's view on the use of the four industry standard approaches to estimating electricity LRMC as described in the Alberta MSA December 2012 report.

Response:

FBC has not undertaken a detailed review the different approaches to estimating LRMC described in the Alberta MSA report. FBC's approach to calculating a LRMC for the purposes of determining the cost-effectiveness of DSM programs is based on its particular circumstances.

238.2.1 Is the methodology used by FBC to calculate the LRMC used in the TRC/UCT consistent with one of these industry standard approaches? Please explain.

Response:

As described in the response to BCUC IR 1.238.1, the methodology used by FBC to calculate the LRMC used in the TRC/UCT is consistent with the California Standard Practice Manual, adapted for FortisBC's circumstance where the Company's avoided supply costs are based on market prices.

The approach FBC has taken in determining its Levelized Cost is analogous to a levelized unit electricity cost, which is described in the MSA paper referred to above[38].

[38] "A Comparison of the LRMC and Price of Electricity in Alberta", December 10, 2012, Alberta Market Surveillance Administrator, Section 2.1.4, page 6.

Given FBC's current long term power supply resources and the market assessment and the resource options report provided in FBC's 2012 Long Term Resource Plan, market purchases were expected to represent FBC's least cost resource to meet the Company's incremental energy demand in the short to medium term.

FBC's January 2013 BC Market energy price provided an updated assessment of the PNW power markets resulting in a downward shift in market pricing.. Therefore, in its levelized unit energy cost approach, FortisBC has used the January 2013 BC market energy price curve update to assess the costs of satisfying future demand and/or demand increment.

238.3 Please compare the FBC LRMC used for the modified TRC with BC Hydro's LRMC components and description, and explain any significant differences.

Response:

The FBC LRMC for the modified TRC is based upon the price of clean energy only resources. The modified TRC utilizes FBC's BC New Clean Resource Price Curve from its 2012 Resource Plan. The price curve was developed from BC Hydro SOP pricing, whose price is representative of the LRMC of clean energy only resources.

BC Hydro's LRMC of firm energy (not energy only) is based on a specific call for power, in this case the 2009 Clean Power Call, encompassing multiple types of clean energy projects located across the province of British Columbia. As a result, BC Hydro's estimate of the LRMC for acquiring firm energy from clean or renewable resources in B.C. must address the different characteristics of clean supply resources in order to evaluate them on a firm energy basis.

FortisBC has not recently acquired clean energy from new energy projects. In 2010 FortisBC acquired a long term capacity only resource from Waneta Expansion Project that is expected to meet fulfills its capacity requirements for the most of the planning period. Given current market price expectations, as represented by the January 2013 BC Market energy price curve update, and the flexibility of its firm resources to store and shape energy purchase, FBC expects to be able to be meet its incremental energy requirements at prices more closely represented by the BC Market energy price curve.

The following table compares the FBC modified TRC (energy only) with the BC Hydro LRMC for firm energy (energy and capacity).

BC Hydro's Long-Run Marginal Cost of Firm Energy Component	BC Hydro's Long-Run Marginal Cost of Firm Energy Component Description	FBC modified TRC Equivalence
Weighted Average Firm Energy Price (FEP) at Plant Gate based on the Clean Power Call awarded projects	Price in $2009 derived from a present value calculation (using an 8% nominal discount rate) that adjusts for varying escalation rates, commercial operation dates and electricity purchase agreement terms; lower than contractual bid price.	Not Equivalent: The FBC LRMC for the modified TRC is a clean energy only resource (not a firm energy price at plant gate), and is based on FBC's BC New Clean Resource Price Curve from its 2012 Resource Plan.
Hourly Firm Adjustor	A deduction from the levelized FEP for proponents that committed to deliver hourly firm energy. The magnitude of the adjuster depended on the proponent's profile of on-peak hourly firm energy. For a project with a "flat" hourly firm energy profile, the adjuster was approximately $4.00/MWh.	None: The modified TRC is for energy only resources; therefore the hourly firm adjustor is not relevant. Additionally, no specific generation projects have been identified against which to asses adjustors for firm energy.
Wind Integration Adjuster	A $10/MWh addition to the levelized FEP of wind projects to account for the incremental cost of integrating wind projects into the BC Hydro generation system.	None: Since FortisBC does not anticipate adding new wind projects in the short to medium term, specific wind integration adjusters are not applicable.
Network Upgrade Adjustor	An addition to the levelized FEP to reflect the costs borne by BC Hydro to interconnect projects to the grid. The estimated network upgrade costs were provided in interconnection studies conducted on a stand-alone basis for each project.	None: Since FortisBC does not anticipate needing new generation projects in the short to medium term, no specific networks upgrades are anticipated.
Cost of Incremental Firm Transmission Adjuster	An addition to the levelized FEP to reflect the general cumulative long-term cost of bulk transmission system reinforcement.	None: FortisBC's bulk transmission system has been reinforced recently, and does not anticipate specific transmission upgrades attributable to supply projects.
Losses Adjuster	An addition to the levelized FEP to reflect the losses associated with delivering the energy from each project location to the Lower Mainland on a stand-alone basis.	None: The BC Hydro SOP price provides different regional base prices dependent on project location. Since the BC New Clean Resource Energy forecast assumes no specific location a losses adjuster is not utilized.
LRMC of Firm Energy: Weighted Average Adjusted FEP for Lower Mainland delivery	Weighted average price for firm energy adjusted for product attributes and for project location relative to the Lower Mainland.	Not Equivalent: The FBC LRMC for the modified TRC is a clean energy only estimate, not a firm energy price for energy delivered to the Lower Mainland.

239.0 Reference: Exhibit B-1-1, Attachment H-4, BC Market Levelized Price, Midgard Consulting Memo to FortisBC, June 2013; Annual Energy Outlook 2013, US Energy Information Administration, Figure 86[39]

LRMC: Midgard June 2013 Memo

Midgard states in a June 2013 memo to FBC "Midgard examined the correlations between Mid-C prices and Henry Hub natural gas prices. The Henry Hub - Mid-C correlations are very high...Midgard feels that the low [greenhouse gas] GHG price adder scenario is the most plausible..." (Attachment H-4)

FBC includes in Attachment H-4 its forward natural gas prices from 2018 onwards at US$5.25 per million Btu. The US Energy Information Administration Annual Energy Outlook 2013 provides a projection of natural gas prices which increases by an average of around 2.4 percent per year, to US$7.83 per million Btu (2011 dollars) in 2040. (page 10)

239.1 Please provide correspondence between FBC and Midgard Consulting which outlined the scope of work required, together with any key assumptions Midgard was directed to make.

Response:

In April 2013 Midgard was asked to update the BC Wholesale Market Forecast it provided to FortisBC. The Energy & Capacity Market Assessment[40] was provided and is dated May 26, 2011. Midgard provided a proposal on April 8.

In its proposal, Midgard proposed using the wholesale natural gas prices to in part derive the wholesale electric curve. In order to be consistent with the forecasts used in by FortisBC Energy Inc to support the gas utility's DSM Plan, FortisBC directed Midgard to use the January 2013 GLJ gas price forecast as the basis of the BC Wholesale Market Price forecast in its correspondence dated April 10, 2013. FortisBC also directed Midgard to use the foreign exchange forecast utilized by GLJ. There was some discussion about whether Midgard should develop its own high and low forecast, or if GLJ had done this. Ultimately only the Expected case was developed. There was also discussion about converting the GLJ AECO forecast to a Sumas forecast or to use the GLJ Henry Hub forecast as the starting point for the Mid-C Wholesale Energy Price Curve. Midgard's preference of using Henry Hub as a starting point was accepted.

On June 10, 2013, FortisBC requested Midgard to provide a further memo so FortisBC could release the Wholesale Market electricity curve.

[39] http://www.eia.gov/forecasts/aeo/source_natural_gas_all.cfm#natgas_prices
[40] FortisBC 2012 Long Term Resource Plan, Appendix B, Section 5.5, Table 5.1.3.3-A.

Please refer to Attachment 239.1 for the supporting correspondence.

239.2 Please explain the basis for the assumption by Midgard that natural gas prices will remain constant in real terms for over 20 years.

<u>Response:</u>

Midgard used the price forecast issued by GLJ Petroleum Consultants Ltd dated 1 January 2013 which can be found at the following link: http://www.gljpc.com/sites/default/files/files/jan13.pdf. GLJ issues an updated forecast every quarter based on its comprehensive review of information available through the end of the previous quarter. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers.

In the Product Price and Market Forecasts for the Canadian Oil and Gas Industry dated 1 January 2013 from GLJ Petroleum Consultants Ltd, the Table 2 price forecast for Natural Gas and Sulphur (Effective January 1, 2013) was:

Year	NYMEX Henry Hub Near Month Contract Constant 2013 $ USD/MMBtu
2014	$4.17
2015	$4.57
2016	$4.95
2017	$5.08
2018	$5.25
2019	$5.25
2020	$5.25
2021	$5.25
2022	$5.25
2023+	$5.25

As indicated in the GLJ Petroleum Consultants forecast, the natural gas price remained constant in 2013 dollars from 2018 through 2023. Thereafter the $5.25 price was assumed to remain constant in real terms. FBC notes that GLJ's NYMEX Henry Hub forecast for the 2014 to 2023 period has not changed since the 1 January 2013 quarterly report.

239.3 Does the FBC estimated LRMC used for the TRC and UCT assume that the generator receives full compensation for their fixed costs over time? If no, please explain why not.

Response:

No. FBC's LRMC used for the TRC and UCT are based on spot market price forecasts, and do not necessarily reflect generators receiving full compensation for their fixed costs over time. Please also refer to the response to BCUC IR 1.240.3.1.

239.4 Please explain on what basis FBC is using a 'low GHG' price adder and translate the GHG adder into an equivalent $/tonne of carbon.

Response:

FortisBC has contracted Midgard to provide an independent forecast of market prices. Midgard determined the low GHG forecast was acceptable. Please refer to the responses to BCSEA IRs 1.13.3 and 1.13.4.

BC Hydro provides the low GHG scenario $/tonne CO_2e forecast in its 2012 Draft IRP, which is provided below:

GHG Price Forecasts Low Gas Scenario[41]

Year	Real $2010 CAD / Metric Tonne of CO2e
2014	$9.5
2015	$10.1
2020	$13.7
2030	$11.5
2040	$21.4

[41] Source: BC Hydro 2012 Draft IRP, Chapter 4, Table 4-2, page 4-17.

239.4.1 Does FBC consider that this $/tonne of carbon is reflective of the long-run marginal cost of emissions in BC? Please explain.

Response:

No.

As BC Hydro states in its 2012 draft IRP "For Scenarios C and E, the B.C. GHG price is lower than the B.C. Carbon tax. Therefore the B.C. GHG price *for thermal generation in B.C.* would incur a minimum cost equivalent to the B.C. Carbon Tax"[42]. Scenario C is the low GHG adder scenario.

However, the low GHG price adder does represent the forecast LRMC of GHGs associated with electricity imports. Please refer to the response to BCSEA IR 1.13.4.1.

[42] BC Hydro 2012 Draft IRP, Chapter 4, Section 4.3.3.3, page 4-19, lines 13-15.

240.0 Reference: FortisBC 2012 RR and ISP, Exhibit B-1-2, p. 79; Estimating LRMC in the National Electricity Market, NERA, 2011, pp. 1 - 4[43]

LRMC: is Mid-C an efficient long-run market proxy

FBC stated in its 2012 Integrated Resource Plan (FBC 2012 Revenue Requirements and ISP Application, Exhibit B-1-2, p. 79): "Although the recession that began in 2008 has dampened electricity demand in the US and Canada, longer term economic growth will erode the region's resource surplus and could quickly increase prices for energy and capacity in the Wholesale market."

NERA December 2011 paper titled Estimating LRMC in the National Electricity Market states on pages 1 to 4 "...if [spot] market prices are significantly and persistently above long run marginal cost (LRMC) then this should, given time, prompt new generation investment to restore prices to these levels...the link between SRMC, LRMC and new investment decisions should mean that, on average, there is no material difference between the value of SRMC and LRMC."

240.1 Please provide an overview of the Mid-C market, including a description of how the Mid-C prices are determined what proportion of energy in that region is traded through Mid-C.

Response:

The Mid-Columbia (Mid-C) trading hub represents the wholesale market for the Pacific Northwest. FBC does not have the data to determine what portion of the energy consumed in the region is traded through Mid-C, but as measured by volume on the Intercontinental Exchange, it is the third largest electricity trading point in the US and second largest in the WECC region. [44]

The Mid-C electricity price index is a weighted average of the transactions that settle at (or are based upon in the case of a financial transaction) the Mid-Columbia trading point.

Historically, the Mid-C electricity index has been traded using different platforms / exchanges (e.g. PLATTS, Intercontinental Exchange (ICE)), but in recent years ICE[45] has become the

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[43] http://www.aemc.gov.au/Media/docs/Technical%20paper-168ea920-eb90-446d-a033-ab07edf8a8a6-0.pdf

[44] http://www.platts.com/IM.Platts.Content/methodologyreferences/methodologyspecs/na_power_method.pdf

[45] The IntercontinentalExchange Inc. (ICE) operates as a global, electronic marketplace for trading both futures and over-the-counter (OTC) energy contracts. In addition to currency and index futures and options, ICE's markets offer access to a range of contracts based on crude oil and refined products, natural gas, power (electricity) and emissions, as well as soft commodities (e.g. coffee, ethanol, orange juice, wood pulp etc.).

dominant exchange for the Mid-C electricity price index. The volume of financial sales on ICE is roughly as large as physical sales[46].

Mid-C was established by the regional balancing authorities as a platform for trading surplus energy and within its area it is the predominant trading point. As the electricity markets have evolved in recent decades, financial trading has become an increasingly important part of the total Mid-C trading volumes. Many of the balancing authorities in the NWPP region contract directly with generators using long term power purchase agreements to meet regulatory or policy requirements, such as Renewable Portfolio Standards. Consequently, Mid-C continues in part to serve as a balancing market where surplus energy is traded.

240.2 Does FBC agree that, for a short-term pricing signal to be a true proxy over time for a long-run pricing signal, the average short-term price should approximate the long-run price over time? If no, please explain.

<u>Response:</u>

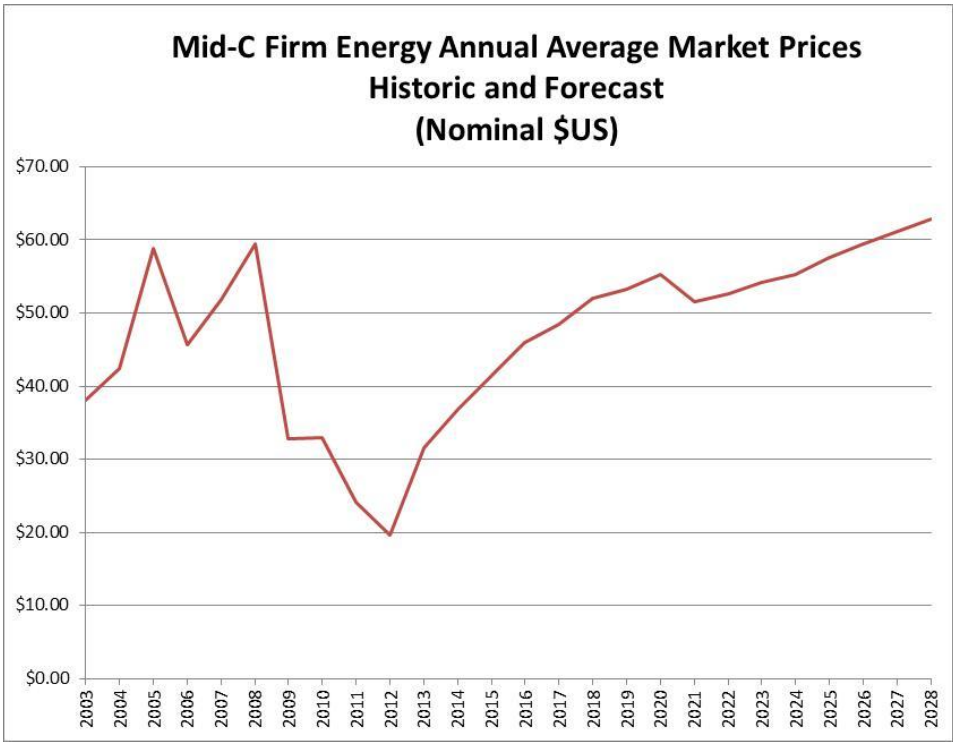
Yes. That is why FBC has utilized the LRMC of Market purchases for the TRC, UCT and part of the mTRC calculation. FBC does not believe the LRMC of New Clean Resources is an appropriate measure for FBC's avoided cost, as FBC's avoided cost over the short to medium term is forecast to be market purchases, not building new generation. Using an improper price signal can create market distortions which could harm FBC's customers.

240.3 Please provide a graph showing the average Mid-C price for the past 10 years, and FBC forecast Mid-C price over the next 15 years.

<u>Response:</u>

Please see the following graph.

[46] Energy Primer – A Handbook of Energy Market Basics, Federal Energy Regulation Comission



240.3.1 Does FBC consider that these prices have been, or are forecast to be, sufficiently high such that a new generator would be able to recover its fixed and variable costs by selling into the Mid-C spot market? Please explain why/why not.

Response:

No, market prices throughout this period would not have supported full cost recovery of a merchant plant selling into the Mid-C spot market. Since 2009, low load growth, large supplies of hydro, significant development of renewable power with low operating costs and lower natural gas prices have combined to contribute to an oversupply situation and in a significant reduction in spot market price forecast. Any generator seeking to build new capacity during this period would be seeking to put in place fixed long term contracts in order to ensure cost recovery.

Recovery of fixed and variable costs in the market depend on a number of factors, including the energy supply balance and generator type. As stated in BC Hydro's 2013 Draft IRP[47]:

[47] BC Hydro Draft 2013 IRP, Chapter 5, Section 5.6.4, page 5-36, lines 8-12.

"Currently there is an energy oversupply in the WECC due to:

- *Slower electricity demand growth since the 2008 recession*
- *Increases in clean or renewable electricity generation driven by U.S. federal and state policies such as RPS and the U.S. tax incentives..."*

In periods of oversupply, market prices tend to reflect the variable costs of the marginal generator, in this case assumed to be a CCGT during the winter and shoulder seasons. During freshet, the marginal generator can be hydro. The combination of high seasonal water levels, must run hydro generation (for environmental purposes) and wind generation will sometimes lead to a significant oversupply situation during certain times of day during in the freshet season, which may result in periods of negative prices during off-peak hours.

There have been times when the Mid-C prices have encouraged building new generation. The Western Energy Crisis of 2000/01 is an extreme example. However these extreme prices were not sustained. In periods where there is no surplus, prices may allow for the recovery of CCGT capital and operating costs, but typically not renewable generation. As described in the BC Hydro statement above, the recent growth in wind generation is tied to renewable portfolio standards and the U.S. production tax incentives.

240.4 Does FBC consider that the broader Mid-C market (for example, the Pacific Northwest and BC) has been in a generation capacity surplus position for the last 10 years, and is expected to continue to be in a capacity surplus position for the next 15 years? Please explain why/why not.

Response:

The Pacific Northwest generation stack in the past has been dominated by large hydro plants with storage and natural gas plants, both capacity rich facilities. In addition there has been a significant development of new wind generation. Over the last 10 years FortisBC would agree that on an average basis, the Pacific Northwest has been in a capacity surplus situation, where merchant gas plants only operate when the price of market energy is greater than their variable costs, without full recovery of their fixed costs. In fact, if utilities maintain adequate planning reserve margins and capacity buffers, there should always be a surplus since if these reserves are not utilized, they may be available to be sold into the market in real time.

There are many factors which may impact the availability of market capacity in the PNW. According to the BC Hydro 2013 Draft IRP, currently there is an energy oversupply in the

WECC. This is due to slower electricity demand growth following the 2008 recession and increases in clean or renewable electricity generation driven by U.S. federal and state policies such as Regional Portfolio Standards and the U.S. tax incentives.[48] This growing fleet of intermittent renewable generation is requiring dynamic scheduling by capacity resources to firm their output. The large hydro dams with storage are continuing to lose their operational flexibility through operational restrictions related to the environment. Because of capacity concerns, some new firm products, such as wind products subject to DSO 216 restrictions, are being offered into the market which are less than the traditional meaning of firm. Utilities have been planning to address load growth through aggressive DSM targets, and may fail to achieve those targets. On top of that, transmission is getting more congested, constraining capacity to within their region.

As discussed in its 2012 Long-Term Resource Plan, given its current power supply firm resource portfolio, FBC still believes it can rely on the market for the short to medium term to meet its energy and capacity gaps cost effectively. But FBC also realizes that this may change. The Company has committed to monitoring the market conditions so it can foresee such an event. In addition, in Table 6.4.1[49], in its 2012 Resource Plan FBC has identified some preferred energy and capacity projects, and continues to evaluate these projects. The selection and timing of these projects will be assessed further in future resource plans.

240.4.1 If it is demonstrated that (i) the broader Mid-C market is not in a long-term surplus position, and (ii) the Mid-C price forecast used by FBC does not signal the need for new generation, does FBC agree that a Mid-C price forecast would not be an efficient market proxy for the long-run cost of new energy. If no, please explain why not.

Response:

Agreed. However the Mid-C would continue to be an efficient market proxy for FBC's LRMC of market purchases, i.e. FBC's avoided cost in the short to medium term as described in the response to BCUC IR 1.238.2.1.

48 BC Hydro 2013 Draft Integrated Resource Plan, Chapter 5, Section 5.6.4, page 5 -36, lines 8-12.
49 BC Hydro 2013 Draft Integrated Resource Plan, Chapter 6, Table 6.4.1, page 86.

241.0 Reference: Exhibit B-1-1, Appendix H, pp. 4, 13, 14, Appendix H-4, Midgard Memo, June 2013

LRMC: quality of supply side energy vs. conserved energy

FBC states in the Application: "The 2012 LTRP and the associated 2012 Long Term DSM Plan were predicated on a levelized market price of $84.94/MWh. Since then, the Company has determined the LRMC has declined to $56.61/MWh..." (Attachment H, page 4)

Midgard Consulting Inc. state in their June 2013 memo to FBC: "the expected cost of electricity in the future is forecast to be closely associated with the expected cost of natural gas..." (Appendix H-4)

FBC states in the Application: "The MTRC includes two key components: the use of a BC "clean" new resource in determining avoided cost of energy for DSM...In the 2012-13 RRA filing this value was defined as BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia...$112/MWh." (Appendix H, pp. 13, 14)

241.1 Please explain why FBC considers that there should be a difference between the LRMC of energy used for the TRC compared to the mTRC.

Response:

FBC considers that the LRMC used in the mTRC is intended to boost marginal measures into passing (exceeding unity) up to the 10% limit prescribed in the DSM Regulation s4.(1.5)(b)(iv). The LRMC used in the standard TRC calculation is based on the Company's estimate of the actual benefit of reduced electricity use.

241.1.1 Does FBC agree that the DSM Regulations do not require the use of a different LRMC of energy estimate for the TRC and the modified TRC? Please explain.

Response:

While the LRMC used to calculate the TRC and mTRC tests could theoretically be the same, in practice the LRMC used in TRC calculations is based on the benefit of actual avoided costs. The regulation itself considers the mTRC and TRC differently.

241.2 Please confirm that the LRMC estimate used by FBC as an input to the TRC and UCT does not represent long-term firm energy. If yes, please explain how.

Response:

The LRMC estimate used by FBC represents firm spot market energy purchased over the long term, or a series of short-term firm contracts indexed to the spot market. It does not represent a long-term firm contract.

241.2.1 Does FBC consider that the energy saved through its DSM programs is superior quality than its supply-side Mid-C based LRMC estimate as the DSM supplied energy is assumed (within reasonable limits) to be firm? Please explain why, why not.

Response:

No. As explained in the response to BCUC IR 1.241.2, the Mid-C LRMC forecast is for firm energy, which can be done on the spot market or in short-term (up to 1 year) blocks. Given FBC's Canal Plant Agreement generation resources, the flexibility in BC Hydro's proposed RS3808 contract, and the Waneta Expansion Project capacity, market purchases have a better ability to be shaped meet FBC's resource gap and to reduce customer costs compared to the broad-based DSM program savings.

241.2.1.1 If no, does this indicate that FBC is not sufficiently conservative in its EM&V of DSM programs? Please explain why/why not.

Response:

No, the broad based DSM program will return reliable energy savings over time. However, traditional DSM measures are a non-firm resource, and cannot be shaped or dispatched.

241.2.2 Does FBC consider that it is standard industry practice to use a non-firm source of energy supply as a supply side LRMC proxy for the TRC and UCT? Please explain.

Response:

Industry practices vary depending on the circumstances and the resource options available to the particular utility. For a precedent, FBC can point to its own recent regulatory history. As FBC states in the Application: “The 2012 LTRP and the associated 2012 Long Term DSM Plan were predicated on a levelized market price of $84.94/MWh. Since then, the Company has determined the LRMC has declined to $56.61/MWh...” (Attachment H, page 4)

As a point of clarification, hourly spot market purchases can be bought firm for the hour, or can be bought from power marketers in short-term firm blocks indexed to the market price. Please refer to the response to BCSEA IR 1.14.1. Also, not all DSM products can be considered firm. Given the current resources in FBC’s resource stack, market purchases are an appropriate LRMC proxy for the TRC and UCT. Please refer to the response to BCUC IR 1.241.3.1

241.3 Please confirm that the LRMC estimate used as an input to the TRC and UCT, despite including a low GHG price adder, does not represent clean energy. If no, please explain.

Response:.

Confirmed. The LRMC estimate represents unspecified source market purchases from the Mid-C market, although a significant component of this power will come from clean energy generators such as wind or hydro.

The GHG adder reflects a forecast of the impact on an unregulated market of generators complying with U.S. GHG regulations. These could include carbon taxes, carbon allowances or other carbon compliance mechanisms. Although this does not represent “clean energy”, the cost of such carbon compliance is reflected in the market price.

241.3.1 Does FBC consider that the energy saved through its DSM programs is superior quality than its supply-side LRMC estimate used for the TRC/UCT in that the energy supplied through DSM is clean? Please explain why/why not.

Response:

No. FBC has had no indications that energy savings obtained through DSM programs is of superior quality to the generic energy from market purchases. FBC knows of no way of physically measuring or differentiating the quality of electrons, whether real, avoided or forecasted.

However, FBC assessment of the avoided cost that could result from DSM measures is based on the flexibility of its current firm resources, both own generation and long term contracted resources, that allows it optimise how it meets load on its system. It is therefore a result of the quality its overall power supply portfolio to meet loads on its system, and the ability to time market purchases to meet any marginal capacity or energy gaps, that supports FBC's current view that market price curve best represents its avoid costs.

241.4 Does FBC consider that the energy saved through its DSM programs is superior quality to its LRMC estimate used for the TRC/UCT in that there will be economic developments benefits associated with DSM programs in its service territory? Please explain why/why not.

Response:

No, FBC does not consider economic development and the creation of jobs when evaluating alternative programs. It would be too challenging and costly to try to quantify the different economic benefits resulting from different programs.

The FEU have, however, evaluated the economic benefits of EEC activity generally as part of their last Conservation Potential Review, in a report called, "Impact of CPR-2010 Natural Gas Savings on the B.C. Economy (2010-2030)". Conclusions from this report include "The analysis determined that the net impacts of DSM programs are overwhelmingly positive for the regional economy as measured by output, GDP, and employment…"

241.5 Please explain how FBC has adjusted its LRMC estimate (i) used for the TRC/UCT and (ii) used for the modified TRC, to reflect the delivered cost of energy. Please include in your response if adjustments were made for: transmission losses, substation losses, distribution losses, regulation and frequency response, spinning reserves, supplemental reserves, reactive power, associated network upgrade costs, and third party wheeling costs.

For each adjustment made, please explain how FBC determined the size of the adjustment and the amount of certainty FBC has around the adjustment (for example, that the losses percentage used reflects actual incremental losses associated with the energy purchased).

Response:

The customer on-site energy savings created by DSM programs are grossed-up by the FBC “line losses”, which incorporate all system losses (transmission, distribution, substation), before either LRMC is applied to calculate the DSM benefits. The “line losses” factor used in the DSM Plan is 8.8% is a planning figure.

For associated network upgrade costs, which FBC interprets as the Deferred Capital Expenditures (DCE) of Transmission & Distribution upgrades, a factor of $35.60 per kW-year is used.

The LRMC derivation, used for the TRC, includes BPA wheeling costs.

No adjustments were made for regulation and frequency response, spinning and supplemental reserves or reactive power.

FBC is confident that the adjustment factors given are a reasonable proxy for the (avoided) costs portrayed, and any variation from them would not have a material impact on the plan TRC ratios filed.

241.5.1 Does FBC consider that its LRMC estimate (i) used for the TRC/UCT and (ii) used for the modified TRC includes all delivery related adjustments such that it is consistent in quality with the energy obtained from its DSM programs? Please explain why/why not.

Response:

Yes. For both (i) and (ii) please refer to the responses to BCUC IRs 1.241.3.1 and 1.241.4.

242.0 Reference: FortisBC Stepped and Stand-By Rates for Transmission Customers, Exhibit B-4, BCUC 1.5.10, BCUC 1.12.1.1; BCUC Decision, FortisBC AMI (Order C-7-13), p. 86; BCUC Decision, FortisBC Residential Including Block (Order G-3-12) pp. 40. 41

LRMC: consistency with other FortisBC applications

FBC states in the Stepped and Stand-By Rates for Transmission Voltage Customers Application:

> "...the proposed Tier 2 rate [$0.09223/kWh] appropriately signals FortisBC's generation [LRMC]. ...FortisBC wants to ensure that the Commission understands that FortisBC's long-run marginal cost from new, clean generation is significantly higher than FortisBC's actual marginal cost of electricity...the proposed [Industrial] Tier 2 price does not represent the cost of shaped energy delivered to the customer site. Nor does it include network losses, ancillary services, and network LRMC, etc." (Exhibit B-4, BCUC 1.5.10, BCUC 1.12.1.1)

The Commission states in the FBC Advanced Metering Infrastructure (AMI) Decision dated July 23, 2013 (Order C-7-13, p. 86):

> "FortisBC states that it would not object to valuing the energy lost due to theft at the full long-run marginal cost of acquiring energy from new resources... FortisBC estimates the long-run marginal cost for acquisition of new resources is $111.96/MWh. Adding 11 percent FortisBC system losses increases the estimate to $125.80/MWh... In valuing the reduction in electricity lost to theft...The Panel considers that a matching principle should apply. Where the energy saving benefit occurs over the long-term, a long-term cost of energy should be used to calculate the value of that benefit. The Panel considers that the reduction in energy lost to theft as a result of AMI provides a long-term benefit to customers. Accordingly,...the Panel considers that the cost of energy should be valued at FortisBC's long-run marginal cost of $125.80/MWh."

The Commission Decision of the FBC Residential Inclining Block (RIB) (Order G-3-12) rate states:

> "In the 2008 BC Hydro Residential Inclining Block (RIB) Decision, the Commission determined that the long-run cost of new supply is the appropriate referent for the Step-2 energy rate...The Panel finds that no new evidence has been provided in this proceeding to cause it to depart from those conclusions. Accordingly, the Commission Panel determines that the long-run marginal cost of new supply continues to be the appropriate referent for the Block-2 energy rate... FortisBC is directed to provide an update of the full long-run marginal cost of

acquiring energy from new resources, including the cost to transport and distribute that energy to the customer as part of the reporting to be submitted in 2014" (pp. 40, 41)

242.1 Please provide the LRMC estimate used by FBC for the purposes of its RIB rate, describe how this value was determined and explain any differences between the LRMC value is used for to the RIB rate and the LRMC value used for the modified TRC.

Response:

In the Residential Conservation Rate (RIB) Application, FBC stated its proxy for LRMC was that from market purchases, at that time calculated to be $84.94 per MWh[50]. During the proceeding FBC also provided a LRMC of new resources if $111.96 per MWh, and a LRMC of new resources of $125.80 per MWh which including 11 percent system losses.[51] Currently, FBC does not use an estimate of LRMC for any purpose in determining the charges included in the RIB rate. Please refer to the response to BCUC IR 1.242.1.1.

In contrast, the LRMC value used for the mTRC is the LRMC of new clean resources, as calculated from the BC New Resources Energy Curve in FortisBC's 2012 Long-Term Resource Plan. That value is $111.96/MWh. The price curve was developed from BC Hydro SOP pricing, whose price is representative of the LRMC of clean energy only resources.

242.1.1 Given that the Commission has already determined that the appropriate reference price for Block 2 of the RIB rate is the LRMC of new supply, please explain why FBC considers that a different reference price should be used for the TRC/UCT.

Response:

The Commission directed FBC to establish an inclining block structure for residential rates and during the regulatory process associated with that application determined that the appropriate reference price for Block 2 of the RIB rate is the LRMC of new supply. Currently, the Company does not use any measure of LRMC in determining the Block 2 rate as the Commission Ordered a different methodology in Order G-3-12. As part of the Directives of G-3-12 the Company is to

[50] RIB Application, Exhibit B-8, Commission Panel IR 7.1 & 7.2
[51] RIB Application, Exhibit B-11, p. 17

provide an in-depth analysis of the full long-run marginal cost of acquiring energy from new resources by April 30, 2014. At the present time, FBC does not have information on what this value would be but considers that the Commission determination is specific to a use for the inclining block rate only.

The LRMC of market purchases is appropriate as a reference price for the TRC/UTC in this Application because that price best reflects the Company's current avoided cost.

242.1.2 Has FBC prepared an update of the LRMC estimate as requested in Order G-3-12? If yes, please provide. If no, please summarise the progress to date.

Response:

FBC has not completed the LRMC estimate as required by Order G-3-12. The requirement for the estimate was to have it available for March 31, 2014. The Company may be in a position to file the estimate prior to the 2014 date as part of the RCR Interim Report that will be filed pursuant to Order G-127-13 which is due on or before October 31, 2013.

242.2 Please provide the LRMC estimate used by FBC for the purposes of its Industrial Stepped Rate application, describe how this value was determined and explain any differences between the LRMC value used for to the RIB rate and the LRMC value used for the modified TRC.

Response:

The proxy for LRMC used by FBC for the purposes of the Industrial Stepped Rate Application was $92.23 /MWh. It was based on the cost of new clean energy resources expressed in real 2011 dollars, which is equivalent to the proxy for LRMC of new clean energy resources of $111.96/MWh expressed in nominal (i.e. un-escalating) dollars used in the AMI and the MTRC described in the response to BCUC IR 1.242.3.

For an explanation of the value used in the RIB rate, please refer to the response to BCUC IR 1.242.1.

242.3 Please explain any differences in the LRMC value used for AMI application and the LRMC in the modified TRC.

Response:

Both the AMI and the mTRC LRMC are based on FBC's LRMC of new clean resources, which is $111.96. This was derived from the New Resources Energy Curve in the FBC 2012 Long Term Resource Plan[52].

As described in the quote above, the AMI added 11 percent FortisBC system losses to the LRMC of new clean resources, which increases the LRMC estimate to $125.80/MWh.

The mTRC uses the LRMC of new clean resources plus the 15% Non-Energy Benefits (NEB) adder allowed under the DSM Regulation, which results in an effective LRMC of $128.75/MWh for mTRC purposes only.

242.3.1 Given that the Commission has already determined that the appropriate reference price for valuing the reduced energy theft resulting from AMI is the LRMC of new supply, please explain why FBC considers that a different reference price should be used to value energy obtained from DSM programs for the TRC/UCT.

Response:

The DSM filing uses the LRMC of new clean resources in calculating the mTRC for up to ten per cent of the DSM portfolio expenditure. For the majority (90%) of the DSM expenditure, FBC uses a value that more closely represents the actual marginal cost of firm energy, based on a market-derived LRMC ($56.61/MWh) as per the 2012 LTRP methodology. The 2011 DSM Regulation provides for this two-step LRMC approach, that was tested in the Company's 2012-13 RRA proceedings and approved by the BCUC.

[52] FortisBC 2012 Long Term Resource Plan, Appendix B, Table 5.2-A, page 20 of 54.

242.4 Does the LRMC estimate used for the modified TRC represent the levelized cost of shaped energy delivered to the customer site over a 15 year period, including network losses, ancillary services, and incremental network costs network LRMC? If no, please explain why not and what adjustments would be required to include these items.

Response:

No. Section 4.1.1(b)(i) of the DSM regulation specifies: “in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia.”

The DSM regulation is specific in that it is the cost of acquiring that energy, not the cost of delivery of that energy to FBC customers. Therefore the other costs described above are not applicable.

Please also refer to the response to BCUC IR 1.238.3.

243.0 Reference: BCUC Decision, FortisBC Inc. 2012-2013 RR and Review of 2012 Integrated System Plan (Order G-110-12), pp. 143-146, Exhibit B-1-2, p. 32; FortisBC Stepped and Stand-By Rates for Transmission Voltage Customers Application, Exhibit B-4, BCUC 1.50.1

LRMC: Last Integrated Resource Plan Decision

The Commission states in its decision on FBC's 2012-2013 RRA and ISP Application (Order G-110-12):

> "The Commission Panel accepts the Long-Term Capital Plan (2014-2031) as being in the public interest. Given the lack of detail in the long-term part (2017-31) and the limited information in the medium term part (2014-16) of the capital plan, the Commission Panel wishes to make it clear that acceptance of the LTCP for 2014-2031 is on that basis." (p. 143)

> "To meet energy needs FortisBC intends to rely on wholesale market purchases in the short and medium term (2012-2020) while continuing to assess new clean energy resources. No energy gap is anticipated until 2018. By 2020, an energy gap of 13 GWh is predicted. In the long-term (2021-2040), this gap is expected to increase by about 14 GWh/year, reaching 287 GWh by 2040... To meet energy needs, new clean energy resources and the Similkameen Hydroelectric Project are expected in the 2021–2040 period..." (p. 146)

FBC states in the 2012 ISP: "It should be noted that FortisBC has no transmission facilities that connect directly with markets outside of BC. Accordingly, FortisBC is dependent on the availability of adequate third-party transmission capacity to serve its needs, putting at risk the long-term reliable availability of wholesale market electricity to serve its growing demand." (2012-2013 RRA and ISP Application, Exhibit B-1-2, p. 32)

FBC states in the Stepped and Stand-By Rates for Transmission Voltage Customers Proceeding: "Nevertheless relying on the market doesn't provide the same reliability and risk protection as securing new generation resources." (Exhibit B-4, BCUC 1.50.1)

243.1 Does FBC consider that Order G-110-12 gave specific approval for an increase in reliance on short-term, non-clean, wholesale market purchases to meet medium and longer-term energy needs? If yes, please explain.

Response:

No, any market term purchase of 63 days or longer will require a separate Commission approval.

Order G-110-12 accepted FortisBC's Long Term Resource Plan meets the requirements of the Act except for the Planning Reserve Margin as set out in Section 7.0 of the Decision.

Specifically with regard to the 2012 Long-Term Resource Plan the Decision states:

> *"The Panel accepts FortisBC's argument that, given there is no capacity gap forecast until sometime in the 2021 – 2040 period, the resource supply/demand analysis provided by FortisBC, supplemented with the Midgard "FortisBC – 2010 Resource Options Report" is sufficient to allow the Panel to accept the 2012 LTRP included in the ISP, subject to the findings in Section 5.1.3 in this Decision with respect to the Planning Reserve Margin. The Commission Panel directs FortisBC to include a full portfolio analysis in its next LTRP."*[53]

> *"Therefore, based on the Commission's Panel's review of the 2012 LTRP as described in this Decision, the Commission Panel finds that the LTRP meets the requirements of the Act with the exception of the proposed section of the plan dealing with the Planning Reserve Margin, which is rejected."*[54]

> *"The Commission Panel directs FortisBC to file its next Long Term Resource Plan by no later than June 30, 2016. The plan is to include a fulsome portfolio analysis as described in the Resource Planning Guidelines."*[55]

FBC stated in the proceeding that it intends to do a more comprehensive analysis of its new resource options, and that along with the portfolio analysis directed by the Commission will be addressed in future resource plans.

243.1.1 When does FBC anticipate that it will no longer be in an energy or capacity surplus position, and how does FBC intend to address these shortfalls?

<u>Response:</u>

According to the 2012 Long-Term Resource Plan, once WAX is in service in 2015 it will address most of the Company's short to medium term capacity gaps. However, on a planning basis FBC will experience its first energy shortage of 3 GWh in 2019, and this will continue to grow as

[53] BCUC Order G-110-12, Decision, Page 147.
[54] BCUC Order G-110-12, Decision, Page 149.
[55] BCUC Order G-110-12, Decision, Page 149.

FBC's load grows. The following table demonstrates the energy gap identified in the Resource Plan.

Year	Annual Energy Gap (GWh)
2020	13
2025	72
2030	145
2035	216
2040	287

As discussed in the Resource Plan, in the short to medium term, FBC expects to meet its energy gap with market purchases, and in the long-term with new resources[56]. As discussed in the same section, this buy-build plan is based on price and load forecasts which will be reviewed regularly. FBC will also be looking at displacing planned BC Hydro RS3808 Tranche 2 power with less expensive resources, which may impact the timing of the decision of when to build new resources.

243.2 Has Mid-C been previously accepted as a proxy for the BC LRMC? If yes, please describe.

Response:

The 2014-2018 DSM Plan and the proposed expenditures are consistent with the methodology used in the 2012 LTRP. As FBC states in the Application: "The 2012 LTRP and the associated 2012 Long Term DSM Plan were predicated on a levelized market price of $84.94/MWh. Since then, the Company has determined the LRMC has declined to $56.61/MWh..."[57]

As described in its 2012 Long-Term Resource Plan, "…given the modest size of the forecast energy and capacity gaps that FortisBC expects to fill in the next decade and especially considering that there are few actual hours of exposure to capacity gaps, purchasing from the Wholesale market in the short to medium term is the economically prudent solution for FortisBC and its ratepayers."[58]

56 FortisBC 2012 Long-Term Resource Plan, Section 1.4, pages 11-12.
57 Exhibit B-1-1, Attachment H, page 4.
58 FortisBC 2012 Long-Term Resource Plan, Section 6.4, page 85, lines 7-11.

FBC will continue to monitor load growth, BC Wholesale market prices and estimated market risks, and will re-evaluate market supply in its next Resource Plan.

244.0 Reference: Exhibit A2-11 Energy Provider Delivered Energy Efficiency[59], p. 64

LRMC: Modeling alternatives

Exhibit A2-11 is a 2013 International Energy Agency report on Energy Provider-Delivered Energy Efficiency. Page 64 states:

> "DSM programme need to be developed and conducted in a phased manner over a period of years. This makes it possible to capture synergies with other activities and adapt in response to changing market, funding, social and even political conditions." (Exhibit A2-11, p. 64)

244.1 Please provide a revised DSM budget by reviewing all potential DSM programs (including all those identified in the most recent Conservation Potential Review) under the following assumptions: (i) no restrictions resulting from FBC inability to scale up DSM programs or offer programs to all customer classes, (ii) unless required to ensure adequacy under Section 3 of the DSM regulations, all programs that pass the TRC and UCT should be undertaken and (iii) revised LRMC for the TRC/UCT as identified below:

244.1.1 <u>LRMC option 1</u>: Use of the LRMC used for the modified TRC as the LRMC for the TRC/UCT. Please provide the supporting details of the calculation, and state all assumptions made.

244.1.2 <u>LRMC option 2</u>: Use of an LRMC based on full recovery over the long term of fixed and variable costs of a combined cycle gas generator, plus a mid-point (rather than low scenario) GHG adder. Please provide the supporting details of the calculation, and state all assumptions made.

244.1.3 <u>LRMC option 3</u>: Use of a LRMC price over a 15 year period, using estimated Mid-C price for all years where FBC expects to be in an energy and capacity surplus position, and switching to the modified TRC LRMC estimate for all subsequent years.

As the proposal is for a 5 year PBR, please then adjust the LRMC estimate upwards to reflect the average levelized LRMC using this approach over the 5 year PBR period. Please provide the supporting details of the calculation, and state all assumptions made.

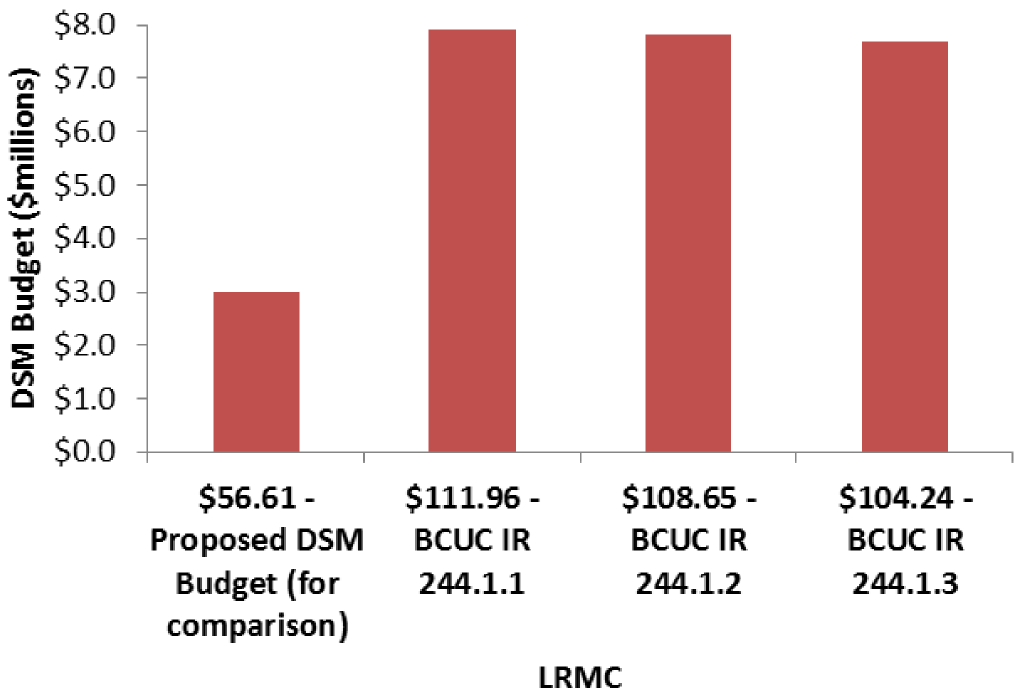
[59] Energy Provider-Delivered Energy Efficiency, International Energy Agency, 2013

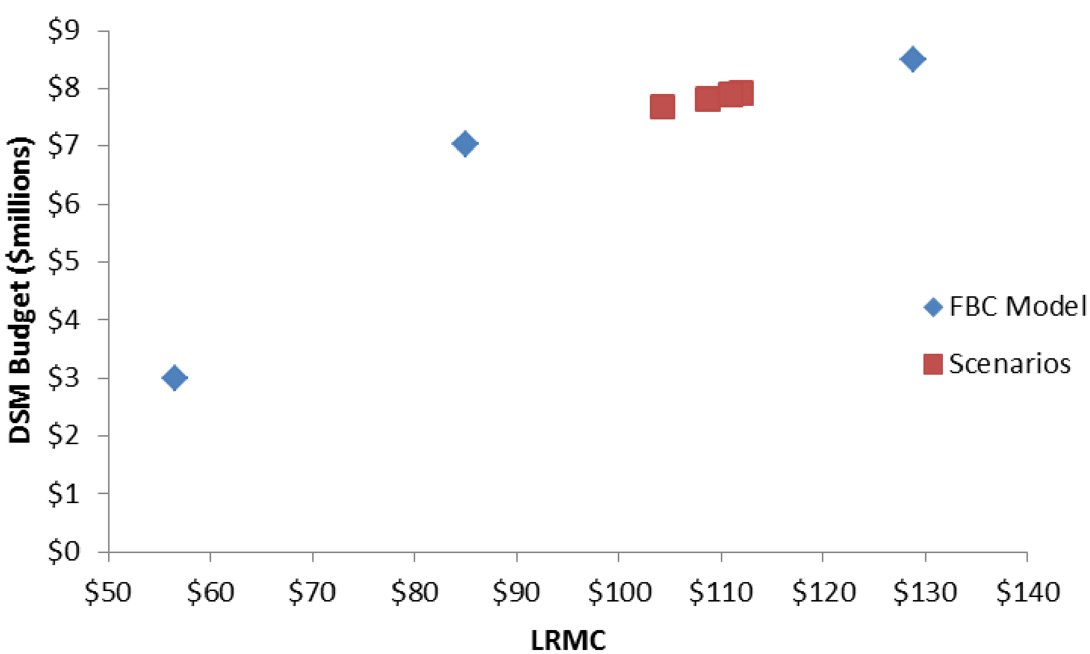
Response:

The following table and figures show FBC's approximate DSM budget using the LRMC scenarios presented in BCUC IRs 1.244.1.1 to 1.244.1.3 under the following assumptions: no restrictions to scale up DSM programs; and that all programs pass the TRC and UCT cost tests.

Plan	LRMC (Nominal)	DSM budget ($m)	FBC Assumptions
Proposed DSM Budget (for comparison)	$56.61	$3.0	LRMC as filed.
BCUC IR 244.1.1	$111.96	$7.9	Marginal cost of power used for mTRC calculations.
BCUC IR 244.1.2	$108.65	$7.8	A 200 MW CCGT operating at a high capacity rate, the GLJ January 2015 gas price forecast, and a mid GHG price forecast in the calculation.
BCUC IR 244.1.3	$104.24	$7.7	Load/resource balance in the 2012 Long-Term Resource Plan, the 2013 Mid-C low GHG price curve update for when FBC was in an energy surplus, and the marginal New Clean resources cost curve developed for the 2012 Long Term Resource Plan when FBC was in an energy deficit.

Note these are high-level DSM budget estimates and have not been prepared in detail. There are a number of key drivers, other than LRMC, which determine a DSM budget including but not limited to: incentives paid (as a proportion of measure costs), resource requirements, and supporting portfolio level components.


DSM Budget ($millions)
$8.0
$7.0
$6.0
$5.0
$4.0
$3.0
$2.0
$1.0
$0.0
$56.61 - Proposed DSM Budget (for comparison)
$111.96 - BCUC IR 244.1.1
$108.65 - BCUC IR 244.1.2
$104.24 - BCUC IR 244.1.3
LRMC


DSM Budget ($millions)
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
$50
$60
$70
$80
$90
$100
$110
$120
$130
$140
LRMC
FBC Model
Scenarios

244.2 Please provide a revised DSM budget using the same three scenarios above, but this time, reduce the DSM budget to reflect FBC's inability (if any) to scale up DSM programs and/or ensure equitable access to DSM programs by all customer classes over the PBR period. Please provide explanations for any adjustments made.

Response:

FBC does not anticipate an inability to scale up DSM programs and/or ensure equitable access to the programs under the scenarios presented in BCUC IR 1.244.1 given sufficient time. The timing of the Decision, and any specific DSM directives, will have an impact on the ramp-up of any alternative scenarios to the filed DSM Plan.

245.0 Reference: Exhibit B-1-1, Section 6.2.1, p. 15

Net-to-Gross Ratio: Spill-over and Free Riders

FBC states that "[h]istorically, the way in which the FBC calculated [net to gross] NTG adjusted the benefits downward for the presumed presence of "free riders", i.e. individuals who participate in an incentive program who would have upgraded their equipment even in the absence of an incentive."

245.1 Please provide the method historically used by FBC to adjust the benefits downward in order to calculate the NTG ratio for each DSM program. In particular, has FBC used a uniform rate of free ridership across program areas and programs? Why or why not? Please also provide the value of the downward adjustment for each program area or program, as the case may be, and the supporting information.

Response:

FBC does not use a uniform rate of free ridership for its programs. FBC uses a free rider rate that is specific to the program. Free rider estimates reflect the characteristics of the program and its target market including customer class (residential, commercial, industrial), market (new construction, retrofit), incentive amounts and structure, program phase, and other factors.

For program planning purposes, estimates of free riders are based on experience from earlier evaluations of the program, experience in other jurisdictions with comparable DSM programs, expert opinion, and/or feedback from industry stakeholders. Evaluations are used to assess the estimate program free riders.

Program evaluations have used a variety of methods to derive estimates of free riders but the majority have used an enhanced self-reporting methodology using surveys of program participants. Representative samples of program participants are asked a series of questions to assess the influence of the program on choice of equipment efficiency, the timing of decisions to replace or upgrade equipment, and quantities purchased (i.e., for programs allowing multiple purchases such as CFLs, etc.). Probabilities of being a free rider are assigned to each response and the product of the probabilities used to derive an estimate of free ridership for each respondent. Supplemental survey questions are used as a double check on the consistency of respondent answers (e.g., overall influence of the program and its incentive, timing of program awareness relative to the decision to upgrade to the energy efficient model, etc.). Participant free rider rates are averaged to determine the overall estimate of program free ridership.

Other methods of assessing free riders include interviews with trade allies (contractors, equipment suppliers) and program field staff.

Refer to the response to BCUC IR 1.260.2 for a table of current NTGR adjustments.

FBC further states that "FBC has included "spill-over" effects, where known, in the NTG which is a recognized approach that is used by other utilities including BC Hydro. 13 As "spill-over" is the conceptual opposite of "free riders", including both effects presents a more complete and balanced view of program impacts."

Footnote 13 states: "2012-2013 RRA Exhibit B-9, BCUC IR 1.210.2"

245.2 Please provide a copy of BCUC IR 1.210.2 in Exhibit B-9 of 2012-2013 RRA and ISP Application.

Response:

Footnote 13 refers to FEI's 2012-2013 Revenue Requirements Application. Please refer to Attachment 245.2 for a copy of FEI's response to BCUC IR 1.210.2.

245.3 Please discuss whether "spill-over" effects are presumed or demonstrated.

Response:

For DSM program planning purposes, estimates of spillover are based on experience from earlier evaluations of the program, evaluations of similar or comparable programs from other jurisdictions, expert opinion, and/or feedback from industry.

Empirical evidence is used in program evaluations to assess the legitimacy and size of spillover estimates used in program plans.

245.4 Please explain the method used by FBC to estimate "spill-over" effects at the most disaggregated level, i.e. program area or program.

Response:

FBC program evaluations that have addressed spill-over have typically used an enhanced self-reporting methodology using representative samples of participants to assess both the qualifying nature of any potential spillover and whether some or all of the spillover is attributable to the program. Depending upon the program, participants are asked about energy efficient equipment purchases or upgrades, changes in behaviours, etc. undertaken outside of program (i.e., without an incentive from FBC). They are then asked to qualify the level of influence their participation in FBC's program had on making these decisions. Information provided by program participants is contrasted with feedback provided by program delivery personnel and, where and when feasible, program trade allies (equipment suppliers, contractors, etc.).

245.4.1 Please provide the values of the "spill-over" estimates by program or program area that FBC included in its 2014-2018 DSM Plan.

Response:

For planning purposes the DSM Plan uses "net" unit measure savings, provided in the 2013 CPR Update, as these reflect the NTGR adjustments (inclusive of any spill-over and free-rider effects) in the measure lists of the referenced utilities.

In the FEU 2012-2013 RRA and Natural Gas Rates Application, the Commission stated on page 171:

> "The Commission Panel agrees that the FEU's current practice of including free riders but not spillover adjusts DSM program savings downwards only and results in a one-sided adjustment to energy savings. However, the Panel believes it would not be appropriate to make a determination on the inclusion of spillover without a full assessment of the merits of including spillover based on a specific set of facts before the Commission. **Accordingly, the Commission Panel makes no determination on the inclusion of spillover in this RRA. The FEU may readdress this issue in future applications.**"

245.5 Does FBC agree that the inclusion of "spill-over" effects should be supported by comprehensive and convincing empirical evidence? If not, why not?

Response:

FBC agrees that all claims to spill-over be supported and justified through empirical evidence collected and analyzed using industry accepted methods and procedures (best practices).

245.5.1 If so, please provide the empirical evidence to support the inclusion of "spill-over" effects in the NTG ratio.

Response:

The 2009 Commercial Lighting M&E report found a 9% spillover rate for custom lighting, however that report has been superseded by the 2012 Commercial Lighting M&E report which did not determine a spillover rate.

Exhibit 23 is an excerpt from the 2009 M&E Commercial Lighting M&E report, showing the spillover calculation:

Custom option spill-over calculations are summarized in Exhibit 23.

Exhibit 23: Spill-over Calculations – Custom Option Participants

Purchased and installed energy efficient lighting outside of program? (Q20)	How energy efficient relative to rebated lights? (Q22)	How influential was program? (Q23)	Frequency (Number of Participants)	Spill-over Score
Yes	Equal or greater	Very influential	1	100%
Yes	Equal or greater	Somewhat influential	2	50%
Yes	Equal or greater	Not at all influential	2	0%
No or Don't know	NA	NA	17	0%
Total n =			**22**	
Weighted Average Spill-over				**9%**

Totals may not sum due to rounding

The 2011 BIP (Retrofit) M&E report found a 12% spillover rate for custom projects. Exhibit 13 is an excerpt from that report showing the spillover calculation:

Exhibit 1: Spillover Calculations

Installed additional EE measures since participating in Building Improvements Program?	Received incentive from FortisBC or other third party?	Influence of FortisBC Building Improvements Program:	Frequency	Spillover Probability	Spillover Score
Yes	No	Very influential	5	1.0	0.185
Yes	No	Somewhat influential	3	0.5	0.056
Yes	No	Not at all influential	6	0.0	0.000
No	Yes	--	12	0.0	0.000
DK	DK	--	1	0.0	0.000
		Total n=	**27**		
Weighted average spillover score =					**24%**

Totals may not sum due to rounding

FBC states that "[w]here adequate estimates are developed or acquired based on the results of an evaluation, free rider and spill-over effects would be accounted for in the NTG ratio as appropriate."

245.6 Please define the term 'adequate' and provide the criteria used to determine whether a free rider or spill-over effect estimate is adequate.

Response:

For program planning purposes, the adequacy of program-specific estimates of spillover or free-ridership rates are based on experience from earlier evaluations of the program, experience in other jurisdictions with comparable DSM programs, expert opinion, and/or feedback from industry stakeholders which suggests that spillover is a likely outcome of program operation. Evaluations are used to assess the legitimacy and size of program spillover.

FBC program evaluations that have addressed spill-over typically rely on a self-reporting methodology using representative samples of participants to assess both the nature of any potential spillover and whether this spillover can be attributed to the program. Program participants are asked about equipment purchases, behaviour changes, or process improvements taken outside of the program that did not receive an incentive from the program.

They are then asked to qualify the level of influence their participation in FBC's program had on making these decisions. Information provided by program participants is contrasted with feedback provided by program delivery personnel and, in some case, program trade allies (contractors, suppliers, etc.).

On page 7 of Appendix H3, Johnson notes that one of the key researchable issues is "measuring free-ridership and spillover."

245.7 Please explain how FEU estimates program uptake, free-rider and rebound estimates.

Response:

FBC assumes for the purpose of this response that the Information Request refers to FBC, not to FEU.

Program Uptake:

FBC uses a market diffusion model that utilizes ramp-rates times economic potential, as provided by EES Consulting as part of the 2013 CPR Update.

Free Riders:

Estimates of free ridership generally need to be done on a program-by-program basis, as they can vary significantly between programs.

For reporting purposes, i.e. the DSM semi-annual year-end report, free-ridership is incorporated in the NTGR, along with the spillover rate if known, to produce the net energy savings which are then reported.

For planning purposes the DSM Plan uses "net" unit measure savings, provided in the 2013 CPR Update, as these reflect the NTGR adjustments in the measure lists of the referenced utilities.

Rebound:

Rebound, or take-back effect, means the customer is saving less energy than anticipated because of a change in their behaviour. For example a customer who, having installed a heat pump, now sets their thermostat a degree or two higher to increase their comfort level.

FBC does not include rebound estimates at this time but notes that to an extent rebound is captured in the realization rates of impact studies.

245.7.1 Are these estimates reviewed by an independent third party? If yes, please describe. If no, please explain why not.

Response:

FBC uses industry accepted practices to develop and evaluate estimates of free riders and spillover. Program planning assumptions for free riders and spillover are assessed and evaluated during impact evaluations. FBC DSM evaluation reports are provided by third party independent consultants, who are qualified M&E practitioners that are selected through a transparent RFP tendering process.

245.8 Please provide research papers on use of spillover and free rider estimates in DSM evaluations.

Response:

FBC understands there is extensive literature on the subject matter in question, but does not have the resources to choose which of the many papers available are most relevant. FBC relies on qualified M&E consultants who, as specialists in their field, ensure the free-ridership and spill-over rates are determined through best practices.

246.0 Reference: Exhibit B-1-1, Appendix H, p. 14

TRC/UCT – Key Inputs: Other

FBC states in the Application "Section 4(1.1)(c) of the DSM Regulation requires the Commission to allow the inclusion of [non-energy benefits] NEBs, the amount of which may be determined either by the Commission based on evidence from the utility or by using a deemed 15 percent adder to the benefits side of the MTRC calculation. FBC uses the 15 percent NEB adder..." (Appendix H, p. 14)

246.1 Please identify the inputs into a TRC/mTRC calculation, and provide an overview of the methodology used to calculate the value of these inputs.

Response:

TRC:

The typical inputs into a TRC calculation are as follows:

- incremental measure costs,
- value for energy savings based on the LRMC, $/MWh
- energy savings per measure, kWh
  - Net energy savings, which incorporate the NTGR
- net to gross ratio (NTGR) incorporating:
  - free rider rate,
  - spillover rate (if applicable),
- effective measure life (EML), incorporating persistence
- program administrative costs, and the
- discount rate.

For measure attributes such as incremental costs, energy savings per measure, free rider rates and measure life, there are a number of ways in which the value of the inputs might be determined, depending on the availability and quality of information.

For planning purposes, FBC uses the unit measure attributes (net unit savings, incremental costs and administration proxy) provided by the consultant who prepared the FBC Conservation Potential Review. Forecasted administration costs are estimated based on previous program data i.e. and escalated by an inflation factor. As the program is in market, key information is obtained from participant feedback on application forms, surveys and ultimately, consumption analysis.

At various stages of the life cycle of a program, these inputs will be subjected to different types of evaluations (see the FBC's EM&V Framework), or new market information may become available. In each case, this new information may lead to adjustments to the inputs.

Program administration costs are estimated using the best available information at the design stage and revised based on actual recorded costs once the program is in market. The methodology for determining the Company's avoided cost (LRMC) of electricity is described elsewhere in detail. The discount rate used to discount future values in the calculation is updated periodically and matches the value used to evaluate supply-side investments.

mTRC:

The inputs into the mTRC calculation are the same as those for the TRC except for the value of the avoided energy consumption and a value that represents additional, non-energy benefits (NEB) not included in the TRC. The methodologies for determining these values are defined by the BC Demand-side Measures Regulation. Currently, the avoided cost of energy in the mTRC calculation is set at the long run marginal cost for new BC clean renewable power, and the non-energy benefits are included by increasing the benefits side of the calculation by 15%.

246.2 Please describe how FBC treats non-FBC incentives (such as LiveSmart) in the TRC/mTRC calculation?

Response:

Incentive costs from any party do not reduce the total cost used in the TRC/mTRC calculation, as they are considered transfer between parties regardless of source e.g. utility incentive or government incentive, and therefore non-FBC incentives do not impact the TRC/mTRC calculation

The costs entered into the TRC calculation are the total incremental costs of the measure compared to the baseline or existing technology in place (including installation costs for retrofit measures), regardless of who incurs them, plus the program administration costs.

246.3 What discount rate has FBC used for the TRC/mTRC calculation? If a societal discount rate is not used, please explain why.

Response:

FBC used an 8% discount rate for the 2014-18 DSM Plan, which represents the Company's past practice for evaluating supply-side investments. The DSM Regulation does not call for the use of a societal discount rate, even for the modified TRC.

246.4 Please provide a summary of all programs where the mTRC is used.

Response:

The following measures used the mTRC in the DSM Plan.

Sector	Program	Measure	TRC B/C ratio	mTRC B/C Ratio
Residential	Building Envelope	Draft proofing	**0.5**	**1.0**
Residential	New Home	Performance path	**0.6**	**1.2**
Residential	Water Heater	Heat Pump Water Heater	**0.8**	**1.5**
Commercial	BIP (new)	Whole Building	**0.98**	**1.7**
Commercial	BIP (retrofit)	Weatherization	**0.9**	**1.8**

246.4.1 Please provide an explanation as to why FBC has used a deemed adder for non-energy benefits of these programs, rather than develop a program-specific estimate.

Response:

FBC used the 15% NEB deemed adder, allowed under the DSM Regulation, because it had no measure or program specific NEB estimates.

247.0 Reference: Exhibit B-1-1, Appendix H-1, 2014-2018 DSM Plan, p. 14

TRC/mTRC/UCT – Program Results

FBC provides a summary of benefit: cost ratios for the 2014-18 DSM Plan on Appendix H-1, page 14 of the Application.

247.1 Please provide the TRC/mTRC and UCT ratios for each individual program proposed in the FBC 2014-2028 DSM Plan. Please also show the UCT results as c/kWh.

Response:

The following table presents the TRC, mTRC, and UCT ratios for each individual program proposed in the FBC 2014-2018 DSM Plan. The utility levelized cost per kWh is also shown below.

Program Area	Benefit/Cost Ratios			
	TRC	mTRC	Utility	Utility Cost (¢/kWh)
Residential Programs				
Building Envelope	1.1	1.3	4.8	1.3
Heat Pumps	1.1	1.1	2.4	2.7
Lighting	1.4	1.4	5.9	1.0
New Home	0.6	1.2	1.2	5.5
Water heating	1.6	1.9	2.1	3.0
Low Income & Rental	0.8	1.4	1.0	7.1
Total	**1.2**	**1.3**	**3.5**	**1.3**
General Service Programs				
Lighting	1.7	2.0	3.4	2.0
BIP	1.1	1.5	3.1	1.6
Irrigation	2.1	2.1	7.3	0.8
Total	**1.4**	**1.7**	**3.3**	**1.8**
Industrial Programs				
Industrial Programs	2.8	2.8	5.7	1.0
Total	**2.8**	**2.8**	**5.7**	**1.0**
All Programs	**1.4**	**1.5**	**3.9**	**1.7**

247.1.1 Please update the information above, using LRMC Option 1, Option 2 and Option 3 calculated previously as the LRMC of energy.

Response:

FBC is unable to provide this level of detail for the different LRMC options: since detailed plans have not been prepared for each of these options. For illustration purposes the table below provides a summary of the benefit cost ratios for a draft of a $7 million dollar DSM plan.

Program Area	Benefit/Cost Ratios			Utility Cost (¢/kWh)
	TRC	mTRC	UCT	
Residential Programs				
Building Envelope	0.9	1.1	2.2	2.9
Heat Pumps	0.7	0.7	3.1	2.2
Lighting	1.4	1.4	3.1	1.8
New Home	0.7	1.3	1.2	5.5
Water heating	0.4	0.4	1.3	7.1
Low Income & Rental	1.3	1.6	1.9	2.6
Total	**0.9**	**0.9**	**2.2**	**2.9**
General Service Programs				
Lighting	1.1	1.7	2.3	3.0
BIP	1.1	1.5	2.4	2.6
Irrigation	2.2	2.2	7.3	0.8
Total	**1.2**	**1.6**	**2.4**	**2.7**
Industrial Programs				
Industrial Programs	3.4	3.4	9.5	0.6
Total	**3.4**	**3.4**	**9.5**	**0.6**
All Programs	**1.1**	**1.2**	**2.4**	**2.8**

247.2 Please provide the TRC/mTRC and UCT ratios for each individual program that has been either eliminated or scaled down in the proposed in the FBC 2014-2028 DSM Plan compared to that previously approved by the Commission. Please also show the UCT results as c/kWh.

Response:

The following table presents the TRC, mTRC, and UCT ratios for each individual program has been either eliminated or scaled down in the proposed FBC 2014-2018 DSM Plan. The utility cost per kWh is also shown below. Blank values indicate that these programs were not included in the plan.

The items listed in the table below show programs that were either eliminated or where the measures available under the previously approved program were scaled back.

Under Residential 'Building Envelope' program we have removed the windows measure under the proposed plan; under the 'Heat Pumps' program we have removed heat pump conversions and geoexchange; and FBC has dropped both 'Appliances' and 'Behavioural' measures. In the Commercial sector street and parking lights measures were eliminated from the commercial lighting program and the Municipal Water Handling Infrastructure program was eliminated altogether.

Program Area	Program Status	Benefit/Cost Ratios			Utility Cost (¢/kWh)
		TRC	mTRC	UCT	
Residential Programs					
Building Envelope	Scaled down	1.1	1.3	4.8	1.3
Heat Pumps	Scaled down	1.1	1.1	2.4	2.7
Appliances	Eliminated	1.1	1.1	0.8	11.5
Behavioural	Eliminated	2.5	2.5	2.3	2.4
General Service Programs					
Lighting	Scaled down	1.7	2.0	3.4	2.0
Municipal (Water Hdling)	Eliminated	1.7	2.1	4.1	1.9

The following table shows a list of measures that were eliminated from the plan. These measures were eliminated because they did not pass the TRC test or exceeded the mTRC cap of 10%.

Sector	Program	Measure
Residential	Building Envelope	Windows - Single
Residential	Building Envelope	Electronic Thermostat
Residential	Heat Pumps	Heat Pump Conversion - Air Source
Residential	Heat Pumps	Heat Pump Upgrade - Ductless
Residential	Heat Pumps	Heat Pump - Geothermal
Residential	Appliances	Clothes Washer

Sector	Program	Measure
Residential	Appliances	Refrigerator
Residential	Electronics	Computers etc.
General Service	Lighting	Streetlights
General Service	Lighting	Parking Lights
General Service	Municipal	Water

247.2.1 Please update the information above, using LRMC Option 1, Option 2 and Option 3 calculated previously as the LRMC of energy.

Response:

FBC is unable to provide this level of detail for the different LRMC options, detailed plans have not been prepared for each of these options.

248.0 Reference: Exhibit B-1-1, Section 1, Appendix H1, p.3; FortisBC 2012-2013 RR and ISP Application, Exhibit B-1-2, Appendix C, 2010 CPR[60]; Overcoming Market Barriers, American Council for an Energy-Efficient Economy, 2013, Executive Summary, pp. 2, 3[61]

Identification of Market Failures/ Conservation Potential Review

FBC states on page 3 of Appendix H1 that "[t]he 2014-18 DSM plan portfolio ... is intended to capture economic potential savings over the long term, as identified in the 2013 CPR update."

FBC 2010 Conservation and Demand Potential Review (CPR) was included as Exhibit B-1-2, Appendix C of FBC 2012-2013 RRA and ISP Application.

The Executive Summary of an American Council for an Energy-Efficient Economy March 2013 paper titled "Overcoming Market Barriers and Using Market Forces to Advance Energy Efficiency" states on pages 2 and 3: "While there are large opportunities for cost-effective energy savings, a variety of barriers stand in the way... A few key barriers are...

- Imperfect information may be the most widespread barrier to energy efficiency. For energy efficiency, the most obvious information barrier is knowledge of the performance of different equipment, technologies, buildings, and other systems…
- Split incentives or principal-agent problems. In energy efficiency a common problem is that the agent making decisions on efficiency investments or actions does not pay the energy bills, and thus has little incentive to reduce them…
- Externalities...
- Imperfect competition..."

248.1 Would FBC agree that the aim of the Conservation and Demand Potential Review (CPR) is to identify areas where there are opportunities for cost-effective investments in efficiency, but where these investments are not currently being made? Please explain.

Response:

The aim of the CPR is to provide a planning document that FBC can use as an ongoing reference tool to:

[60] http://www.bcuc.com/Documents/Proceedings/2011/DOC_28033_B-1-2-FBC-Volume-2.pdf pdf page 523

[61] http://www.aceee.org/research-report/e136

- Determine the technical, economic and achievable DSM potential
- Develop a long-range energy efficiency strategy
- Design and implement energy efficiency programs
- Assess the impact of energy efficiency programs on both peak and annual loads
- Set annual energy efficiency targets and budgets

FBC uses the CPR to identify potential energy efficiency opportunities, the majority of which are not being readily adopted by its customers. This helps to inform the development of FBC's programs. However, it should be emphasized that this report does not aim to either set specific program targets or provide program design.

To be considered for review in the CPR, measures must be technically proven and commercially available but not fully adopted within the applicable utility service territories. Therefore, they present DSM opportunities to address customer investments and behaviours which are sub-optimal from a societal perspective. However, what the CPR does not address are the specific market failures that have led to the sub-optimal societal decisions.

In terms of behaviour measures, there are a wide number of behaviours that homeowners and building occupants can undertake that affect electricity consumption. For the CPR study, the number of behaviours are narrowed by looking at the potential size of the impact, the availability of information, and by consulting with applicable DSM program personnel.

248.2 Please provide a copy of the 2013 CPR update and explain any changes in key assumptions used.

Response:

Please refer to Attachment 248.2 for the 2013 CPR Update.

248.2.1 Please explain when the next CPR update is planned, and how much has been budgeted for this update.

Response:

FBC believes the 2013 CPR Update is sufficient for the duration of the 2013-18 DSM Plan filing period.

There have been preliminary discussions with FEU and BC Hydro on the possibility of a combined, province-wide CPR as early as 2015. Due to the uncertainty as to the timing, budget cost and allocation of costs, or whether this will proceed at all, FBC has not budgeted for this item.

248.2.2 Does FBC consider that there would be benefit if one BC CPR was undertaken, instead of separate CPRs from FEU, FBC and BC Hydro? Please explain why/why not.

Response:

At this point, only preliminary discussions have occurred between the FEU, FBC and BC Hydro on what the extent of a 2015 CPR collaboration would be. In-depth discussions will not take place until 2014. As stated in the response to BCUC IR 1.248.2.1, FBC believes the 2013 CPR Update will suffice over the PBR filing period.

At this time though, it is FortisBC's intent to pursue developing one 2015 CPR study in collaboration with FEU, BC Hydro and the Province which would examine both natural gas and electricity conservation potential, provided it believes there is sufficient additional value. FortisBC will submit an additional budget request if needed.

248.2.3 How does FEU plan to incorporate the updated results into its DSM plan?

Response:

FBC assumes this question was intended for itself, not FEU.

The 2014-18 DSM Plan already incorporates the necessary elements of the 2013 CPR Update, including the updated potential, costs and ramp rates for each measure considered.

248.3 Does the FBC acquisition of the City of Kelowna have any impact on the CPR or DSM programs offered by FBC? Please explain why/why not.

Response:

No, because the 2013 CPR Update already includes the CoK customers.

248.4 Does FBC agree that changes to the size of incentives provided in DSM programs, and rate design changes such as the RIB rate, may be able to mitigate some market barriers to energy efficiency, but that they cannot be relied on to address some of the most common market barriers (imperfect information and split incentives)? If no, please explain why not.

Response:

Agreed.

248.5 Please confirm that FBC is focused on identifying and mitigating all market barriers to electricity related energy efficiency, and not just those which can be mitigated through the provision of an incentive. If unable to confirm, please explain why not.

Response:

FBC conducts literature reviews, as well as primary research to determine the barriers customers experience that limit participation in making energy improvements to buildings and equipment and/or behaviour changes. To address the identified barriers, FBC has implemented several innovative and successful programs.

The most impactful is the Energy Diet concept, which employs intensive community-based marketing strategy and tactics. (The pilot project, Rossland Energy Diet, resulted in a 16% participation rate in the LiveSmart BC program during a time when other communities across

BC experienced an average 1.5% participation rate.) The Energy Diet programs have been expanded across FBC's service territory in 2013. It also has been adopted by communities served by BC Hydro and has received significant recognition by CEE (Consortium for Energy Efficiency) and BECC (Behaviour Energy Climate Change) organizations.

FBC has implemented a number of additional behavioural and/or direct installation programs for hard-to-reach customers. In each instance the programs were highly successful, exceeding goals and objectives. For example:

- FLIP small commercial business direct install lighting retrofits (partnership with Ministry of Energy and Mines).
- Low-Income direct install lighting (partnership with BC Non-Profit Housing Association, and co-funding from BC MEM).
- Building Optimization Program (energy information systems for large institutional and commercial customers which combines behaviour change, technological information and building envelope and equipment improvements to reduce energy usage).

248.5.1 Please describe the process used by FBC to identify the market barriers causing customers to make sub-optimal investment/usage decisions.

Response:

FortisBC regularly conducts literature reviews and has conducted primary focus group and survey research to determine barriers to customer participation. It has then followed up with pilot projects, if indicated, to test program offers that address the identified barriers.

In addition to conducting its own research, it partners regularly with BC Hydro and FEU to conduct larger research projects (for example, LiveSmart BC Evaluation Report, and ECAP focus group research with Dunsky and Associates).

248.5.2 Which programs does FBC have, or plan to develop, that address the unique market barriers to DSM of (i) First Nation communities and (ii) renters?

Response:

FBC is in the midst of delivering a modified ECAP (Energy Conservation Assistance Program) direct installation program for three First Nations communities in its service area. The program provides 150 energy assessments (accompanied by direct installation of energy saving kit measures), 80 building envelope and 60 heating system improvements. The costs of this program are being shared with the BC Ministry of Energy and Mines.

FBC worked closely with the Penticton Indian Band over the past two years to help it secure additional funding and professional building expertise (as well as provide its own rebates) to build 10 super-efficient rental homes on the reserve.

FBC has worked with the BC non-profit Housing Association (BCNPHA) over the past several years, and completed direct install common area lighting upgrades. A pilot project is currently underway to identify other rental stock and offer an integrated energy assessment (of gas and electric measures) and provide in-suite measures (CFLs, low-flow showerheads etc.). If this pilot is successful it will be extended to the balance of the FBC service area.

248.6 Please explain what effect, if any, the residential RIB rate has had on the FBC offered DSM programs. Please include in your response whether FBC has attempted to mitigate bill impacts for high use residential customers by developing (or ramping up) DSM programs specifically targeted to this customer segment.

Response:

FBC has not seen any RIB rate effect on DSM programs per se. The Reduce Your Use offer, to provide free energy assessments to higher-use customers, had modest take-up (please refer to the response to BCUC IR 1.256.1).

Negative customer reaction to the RIB rate was a partial driver in the Company's decision to accelerate the roll-out of the community Energy Diets program across the FBC service area in 2013.

248.7 Please provide an updated Table 19 (Residential) and Table 29 (Commercial) of the 2010 CPR to include the following additional columns: (i) average TRC levelized cost $/MWh (2013 dollars), (ii) average UCT levelized cost $/MWh (2013 dollars). Please describe all assumptions used.

Response:

A CPR Update was prepared for FBC in 2013. The following tables are similar to those presented in the 2010 CPR and contain a set of updated figures.

Those measures with a zero value did not pass the cost-effectiveness screening. They are not cost effective under this scenario and are therefore not included in the plan.

Residential 20-Year Achievable EE Savings and Cost Summary (2013$)

	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Average UCT Levelized Cost $/MWh	Weighted B/C Ratio	Achievable Savings Potential MWh
Appliances Total		**$15,723**	**11**	**6**	**$37.01**	**$14.49**	**4.38**	**92.2**
Clothes Dryer	20YearEven	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Clothes Washer	15YearEven	$1,021	2.1	0.2	$86.57	$46.62	5.66	1.1
Cooking	20YearEven	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Dishwasher	20YearEven	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Freezer	15YearEven	$1,254	0.4	0.5	$28.99	$15.61	2.82	4.5
Lighting	ResLight	$0	1.6	1.2	$17.47	$16.28	3.05	19.3
Refrigerator	20YearEven	$1,341	0.6	0.5	$19.98	$10.76	2.53	5.0
Computers etc.	EmergTech	$361	0.1	0.1	$27.78	$4.11	2.21	2.1
Consumer Electronics	Electronics	$9,093	3.6	2.4	$48.00	$13.94	4.77	51.3
Water Heater	EmergTech	$306	0.1	0.1	$37.90	$20.41	1.33	0.6
Other Water Heating	20YearEven	$2,347	2.5	1.2	$24.92	$13.42	7.62	8.3
Space Conditioning Total		**$50,334**	**23.5**	**6.8**	**$28.67**	**$11.43**	**1.71**	**45.1**
Insulation	20YearEven	$12,580	6.3	3.5	$35.83	$13.45	1.67	30.1
Windows	20YearEven	$1,169	2.0	1.1	$3.33	$1.25	1.73	9.3
HP Conversion - Air Source	20YearEven	$123	0.0	0.0	$45.07	$24.27	1.09	0.2
HP Upgrade - Air Source	20YearEven	$2,108	0.6	0.3	$45.18	$24.33	1.09	2.8
HP Upgrade - Ductless	EmergTech	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
HP - Geothermal	EmergTech	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Window AC	20YearEven	$478	0.0	1.8	$18.26	$9.83	2.85	2.7

Residential 20-Year Achievable EE Savings and Cost Summary (2013$)

	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Average UCT Levelized Cost $/MWh	Weighted B/C Ratio	Achievable Savings Potential MWh
Electronic Thermostat	20YearEven	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
HVAC	20YearEven	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Whole House	EnerGuide90	$0	0.0	0.0	$0.00	$0.00	0.00	0.0
Electric Thermal Storage	20YearEven	$33,875	14.6	0.0	NA	NA	1.23	0.0
Total		**$66,057**	**34.4**	**12.8**	**$34.27**	**$13.49**	**3.5**	**137.3**

Note: rows with all zeros indicate the measures are not cost-effective

Commercial 20-Year Achievable Energy Efficiency Savings and Cost Summary (2013$)

	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Average UCT Levelized Cost $/MWh	Weighted Benefit-Cost Ratio	Achievable Savings Potential MWh
Existing Lighting	20YearDeclining	$6,419	10.3	7.6	$15.04	$3.71	1.98	36,198
New Lighting	New Lighting - Program	$13,826	8.2	6.1	$47.36	$22.48	1.28	28,989
Cooking	20YearEven	$933	0.5	0.7	$27.69	$14.91	2.02	3,417
Network PC Power Management	20YearEven	$1,401	0.6	2.5	$24.51	$13.20	2.50	11,532
Municipal Wastewater	15YearEven	$4,391	0.8	0.8	$39.15	$40.46	1.59	11,372
Municipal Water	15YearEven	$0	0.0	0.0		$0.00		-
Pre-Rinse Valve	5YearEven	$85	0.0	0.0	$47.52	$25.59	1.29	361
Computer Servers	New Lighting - Program	$0	0.0	0.0		$0.00		-
Streetlights	Accelerated 10-year	$408	0.1	0.0	$22.44	$60.99	2.74	1,291
Commercial Refrigeration	20YearEven	$620	0.0	0.1	$12.75	$11.48	2	379
HVAC	20YearEven	$4,346	0.9	0.9	$33.41	$14.62	2.07	9,387
Whole Building	20YearEven	$269	0.2	0.2	$23.27	$10.25	2.46	715
Grocery Store Measures	15YearEven	$3,052	0.7	2.3	$28.93	$14.32	2.29	12,335
Lighting Controls	20YearEven	$332	0.0	0.2	$26.43	$13.33	3.10	1,032
Parking Lighting	20YearEven	$2,443	0.2	0.2	$53.99	$26.91	1.05	

Commercial 20-Year Achievable Energy Efficiency Savings and Cost Summary (2013$)

	Ramp Rate	Total Measure Cost ($1000s)	Winter Peak Savings MW	Summer Peak Savings MW	Average TRC Levelized Cost $/MWh	Average UCT Levelized Cost $/MWh	Weighted Benefit-Cost Ratio	Achievable Savings Potential MWh
								5,493
Exit Lights	10YearEven	$0	0.0	0.0		$0.00		-
Weatherization	20YearEven	$380	0.1	0.1	$30.10	$13.87	2.09	895
Total		**$38,905**	**22.7**	**21.8**	**$31.03**	**$16.50**	**1.85**	**123,396**

Some assumptions include:

Conservation Potential Assumptions	
Avoided Cost, Levelized $2013/MWh	$56.61
Program Administration Costs	30%
Utility Incentive	40%
Achievability Adjustment	90%

The TRC levelized cost includes all measure costs (incremental capital cost), O&M, program administrative costs, and any other associated costs. These are levelized over the lifetime of the measure. In some cases the O&M costs over the life of the measure are negative (i.e., savings) and can be greater than the measure's incremental cost; therefore, the TRC levelized cost is negative.

The UCT includes only the utility portion of the cost provided through incentives plus the administrative costs for overhead, marketing, etc. for running the programs.

These assumptions are also true for the Industrial and Agricultural sectors.

248.7.1 Please provide an estimate of the average TRC levelized cost $/MWh (2013 dollars), and the average UCT levelized cost $/MWh (2013 dollars) for (i) all industrial potential measures included in table 42 in the 2010 CPR, (ii) all irrigation potential measures included in table 46 of the 2010 CPR, and (iii) all residential and commercial behaviour measures included in table 64 in the 2010 CPR. Please describe all assumptions used.

Response:

A CPR Update was prepared for FBC in 2013. The following tables are similar to those presented in the 2010 CPR and contain a set of updated figures.

(i) Industrial

Industrial Achievable Potential and Levelized Cost - Adjusted by Year Using Ramp Rates GWh

			Year					
		Ramp Rate	1	5	10	20	Weighted TRC LC ($/MWh)	Weighted UCT LC ($/MWh)
Cross-Industry Systems	Compressed Air	10YearEven	0.33	1.69	3.31	3.82	21.39	18.50
Cross-Industry Systems	Lighting	20YearEven	0.18	0.90	1.80	3.60	18.70	13.38
Cross-Industry Systems	Fans	10YearEven	0.27	1.35	2.69	5.19	31.69	13.22
Cross-Industry Systems	Pumps	20YearEven	0.08	0.42	0.83	1.66	20.63	21.75
Cross-Industry Systems	Transformers	20YearEven	0.01	0.04	0.07	0.14	19.03	29.60
Cross-Industry Systems	Belts	10YearEven	0.00	0.00	0.00	0.00	36.73	13.62
Cross-Industry Systems	Material Handling	New Measure Medium	0.00	0.00	0.00	0.00	0.00	0.00
Cross-Industry Systems	Motors	20YearEven	0.01	0.05	0.11	0.22	87.28	62.46
Industry-Specific Process	Hi-Tech	10YearEven	0.00	0.02	0.03	0.03	12.46	8.92
Industry-Specific Process	Paper	20YearEven	0.01	0.03	0.06	0.11	139.61	99.92
Industry-Specific Process	Food Processing	10YearEven	0.03	0.15	0.27	0.30	54.21	9.89
Industry-Specific Process	Mining Process	20YearEven	0.00	0.00	0.00	0.00	79.43	26.90
Industry-Specific Process	Wood	20YearEven	0.15	0.74	1.49	2.98	-66.24	41.74
Industry-Specific Process	Food Storage	20YearEven	0.12	0.60	1.20	2.39	45.12	32.29
Whole Plant	Plant Energy Management	New Measure Medium	0.04	0.36	1.03	2.37	36.44	22.06
Whole Plant	Energy Project Management	New Measure Medium	0.02	0.16	0.45	1.04	55.07	2.77
Whole Plant	Integrated Plant Energy Management	New Measure Medium	0.01	0.14	0.40	0.92	-0.21	15.86
Total (MWh)			1.2	6.6	13.7	24.8		

(ii) Irrigation

Irrigation Hardware Measures						
Measure Name	**Incremental Capital Cost ($/unit)**	**Measure Life (yr)**	**Savings per Applicable Acre (kwh/yr)**	**Applicable Acres**	**TRC Levelized Cost ($/MWh)**	**UCT Levelized Cost ($/MWh)**
Convert High Pressure Center Pivot to Low pressure system	$58	10	504	20%	17.15	12.01
Convert Medium Pressure Center Pivot to Low pressure system	$22	10	336	15%	9.76	6.83
Pump, Nozzle & Gasket Replacement Average Well	$111	10	412	11%	40.15	28.11
Pump, Nozzle & Gasket Replacement Deep Well	$134	10	765	19%	26.10	18.27

(iii) The residential and commercial behaviour measures were estimated to be $30/MWh. The IHD program is $80/MWh. Levelized costs were not estimated separately for each of the individual behaviour measures. There is very little reliable data available regarding the cost and persistence of behaviour measures.

248.8 Please provide an updated Table 24 (Residential), Table 33 (Commercial), Table 42 (Industrial) Table 47 (Irrigation), and Table 65 (Behaviour) of the 2010 CPR to show (i) actual/forecast GWh savings achieved since the CPR was prepared to the start of the PBR period and (ii) forecast GWh savings expected over the PBR period. Please describe all assumptions used.

Response:

A new CPR was prepared for FBC in 2013. The following tables are similar to those presented in the 2010 CPR and contain a set of updated figures.

Please refer to BCSEA IR 1.12.9.1 for an overview of FBC's actual, approved, and planned DSM savings from 2008 to 2018.

The forecasted potential by sector for 2014 through 2018 is shown in the table below – assuming a LRMC of $56.61. It is somewhat difficult to compare in greater detail as the program names and types have changes over the years, and the forecasted potential typically includes more detail.

Total Program Potential by Sector and by Year 2014 – 2018 (MWh)					
Savings	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	5,797	5,713	5,630	5,597	5,758
Commercial	8,264	8,260	8,161	8,014	7,726
Industrial	1,226	1,277	1,327	1,378	1,429
Irrigation	490	490	490	490	490
Behavioural	2,566	2,784	3,103	3,568	4,269
Total	**18,342**	**18,523**	**18,710**	**19,047**	**19,671**
Cumulative DSM	**18,342**	**36,865**	**55,575**	**74,622**	**94,293**

Residential:

Residential Program Achievable Energy Efficiency Potential (GWh)				
Measure Category	**Year 1 (2014)**	**Year 5**	**Year 10**	**Year 20**
Weatherization	2.0	9.8	19.7	39.4
Water Heating	0.4	2.1	4.3	8.9
Lighting	1.5	6.0	10.8	19.3
Consumer Electronics	0.3	2.5	6.3	14.0
Heat Pump Upgrade	0.1	0.7	1.4	2.8
Appliances	0.6	3.1	6.2	10.6
HVAC	0.8	4.1	8.1	16.3
Heat Pump Conversion	0.0	0.0	0.1	0.2
Computers etc.	0.02	0.2	0.6	2.1
Whole House	-	-	-	-
Total	**5.80**	**28.49**	**57.56**	**113.58**

Commercial:

Commercial Program Achievable Energy Efficiency Potential GWh				
Measure Category	**1 Year**	**5 Year**	**10 Year**	**20 Year**
Lighting	5.3	25.6	46.9	73.9
HVAC	0.5	2.3	4.7	9.4
Grocery Store Measures	0.8	4.1	8.2	12.3
Municipal	0.8	3.8	7.6	11.4

Commercial Program Achievable Energy Efficiency Potential GWh				
Measure Category	**1 Year**	**5 Year**	**10 Year**	**20 Year**
Whole Building	0.0	0.2	0.4	0.7
Computer Servers	0.0	0.0	0.0	0.0
Cooking	0.2	0.9	1.7	3.4
Weatherization	0.0	0.2	0.4	0.9
Commercial Refrigeration	0.02	0.1	0.2	0.4
Pre-Rinse Valve	0.07	0.4	0.4	0.4
Network PC Power Management	0.577	2.88	5.77	11.53
Total	**8.3**	**40.4**	**76.3**	**124.3**

Industrial – Please refer to the response to BCUC IR 248.7.1.

Irrigation:

Irrigation Potential				
	2030 Consumption (MWh)	**2033 Technical Potential (MWh)**	**Achievable %**	**2033 Achievable Potential (MWh)**
Irrigation	52,071	12,715	77%	9,791

248.8.1 Please identify any end-uses identified in the CPR for which FBC either does not have a DSM program, or has a DSM program but has chosen to not expand it to meet achievable potential targets. Please explain why.

Response:

The specific end-use where FBC does not offer a DSM program is consumer electronics, such as televisions and computer monitors. The volume and diversity of products in this category make it impractical for FBC to offer an end-user rebate program. Past attempts to offer a “spiff”, i.e. sales incentive, resulted in limited participation by a small number of retailers. In addition, measures are being undertaken by regulators and manufacturers to reduce the electricity use (active and standby) of consumer electronics.

Major appliances is another end-use which has been discontinued in the 2014-18 DSM Plan due to market transformation, i.e. Energy Star products are now the norm.

Behavioural programs have also been discontinued due to a lack of certainty in the savings, i.e. hard-wired measures are given precedence and that behavioural programs are resource intensive.

Under the 2014-18 DSM Plan, FBC has opted to focus its efforts on programs with higher benefit cost ratios (while still maintaining a diverse mix across customer classes) as well as those programs that have historically had better market uptake.

248.9 Does FBC consider that there have been any significant changes to the value of demand response on its network since 2010? Please explain.

Response:

While FBC expects to have sufficient capacity available to meet peak expected loads for some time, a demand response option is always of benefit to assist with operational emergencies. As such its main value to the FBC system would be as a reliable, fast acting, source of immediate emergency capacity. In this regard there has been no change in its value to the system since 2010.

248.9.1 Please identify the DSM programs FBC has, if any, specifically designed to reduce system peak and the need for new capacity.

Response:

The benefits from the identified economic DSM programs are derived primarily from energy reduction, although any associated capacity benefits are also included.

Past program activities included the promotion of ETS (electric thermal storage) heaters, which provide a primarily capacity reduction benefit, but there was limited customer take-up. Furthermore, the closure of the TOU rate removes any potential cost savings a new participant would enjoy by installing such a device.

248.10 To what extent does FBC leverage off its access to customer electricity consumption data in the design and delivery of DSM programs?

Response:

To a limited extent FBC leverages customer consumption data, for instance, residential aggregate consumption data was used to develop a targeted mailing list for customers qualified for the Reduce Your Use offer.

248.10.1 Could this data be made available to third parties wishing to provide DSM services to customers? Pease explain how customer privacy could be protected.

Response:

Yes, but only if the customer(s) agree to share their billing data. This could be enabled, and customer privacy protected, through a "Green Button" initiative similar to that implemented in California, in which customers can opt to send their consumption data to third-parties.

248.11 Please explain how FBC has arrived at the DSM funding split between residential, commercial and industrial customer.

Response:

The proposed sector spends, are budgeted from the "ground up" within the residential, commercial and industrial sectors, based largely on economic potential. Sector budgeting begins with individual end-use measures, rolled up into programs with energy savings (kWh) calculated using the CPR Update economic potential x ramp-rate approach, tempered by past program take-up. The individual program target kWh savings are multiplied by the plan utility incentives, plus allocated program administration costs to arrive at sector budgets.

248.12 Please provide an overview of the make-up of the Advisory Group, the selection process, and provide the terms of reference. Please provide a breakdown by interest group.

Response:

Please refer to Attachment 248.12 for DSMAC Terms of Reference.

The DSM Advisory Committee comprises FBC staff, customers and/or customer interest groups, and businesses or associations with a direct interest in DSM in the FortisBC service territory.

The non-FBC members shall be comprised of:

- A minimum of four members representing customers and/or customer interest groups from a variety of customer classes, including wholesale, residential, general service and industrial;
- A maximum of two members representing businesses or associations;
- Members from all regions of the Company's service area, specifically the South Okanagan-Similkameen, Kelowna, and the West Kootenay-Boundary;
- BC Utilities Commission and Ministry of Energy and Mines staff who serve ex officio;
- Members of the Committee may nominate candidates for membership from time to time as vacancies occur. New members must be accepted by a majority of members and FortisBC.

249.0 Reference: Energy Conservation and Demand Management, London Hydro, 2012, p. 70[62]

DSM Sales Focus

A Report by London Hydro (EM-12-04) states: "London Hydro has traditionally approached [Conservation and Demand Management (CDM)] as a "sales" activity and indeed all staff receives sales training (from outside experienced facilitators) with ongoing workshops to reinforce these skills." (p. 70)

249.1 Does FBC consider its DSM role is to develop and sell cost effective DSM products and services to its customers? Please explain why/why not.

Response:

In some ways DSM can be likened to a sales process, e.g. identifying market potential, preparing kWh "sales" targets, addressing market barriers and proactively contacting key account customers.

The Company also has broader roles to play with its PowerSense DSM program, including public awareness (promoting a Conservation Culture) and providing education programs.

249.1.1 Does FBC consider DSM to be closer in similarity to products and services offered in a competitive market, or products and services offered in a monopoly market? Please explain why.

Response:

DSM programs, as structured in the BC context have elements of both competitive and monopoly markets.

Due to the structure of a regulated utility, it realizes the benefits of reduced load, so it is logical for the monopoly utility to offer incentives for these programs.

DSM measures are purchased in a competitive market, however, with the utility generally simply providing financial incentives, allowing the customer choose the specific product and service provider they wish to use.

[62] http://www.londonhydro.com/@assets/uploads/pages-270/cdm_annualreport2011_final.pdf

249.2 Does FBC bundle together its DSM programs, both internally and with other service providers, to provide a 'packaged DSM' service for customers? Please explain.

Response:

FBC frequently bundles its program offers. For example, community Energy Diets are a marketing program that bundles all its residential programs together (Home Improvement Program, Residential Efficiency Loan Program, Appliances, etc.). Bundling helps reduce customer confusion about programs and enhances educational opportunities. Similarly, the CEM certified Technical Advisors who work with one-on-one with commercial and industrial customers offer bundled commercial programs (Building Improvement Program, Commercial Lighting, Building Optimization Program, New Building Program, etc.). They make recommendations based on the customers' needs, and encourage customers to bundle projects (short and long life measures) to optimize their incentive.

FBC also regularly works with external service providers such as contractors and engineering consultants, EE non-profit organizations and other utilities to deliver programs as cost effectively as possible.

249.2.1 Does FBC offer DSM 'while quantities last/for a limited time only' sales. If no, please explain why not. If yes, please describe.

Response:

FBC regularly makes "while quantities last" marketing offers for residential sector programs. For example, the community Energy Diets are designed using sales promotional concepts. The program is only offered for a limited time, there are a limited number of subsidies, first-come-first-served, etc. And these offers are advertised using that terminology. They have been very effective to make customers act in a timely fashion.

Similarly, all the residential programs are time limited offers, which are advertised as such. For example, the Heat Pump Maintenance Program ends October 31 and the Appliance Program ends December, 31.

The commercial, institutional and industrial programs have longer timelines, which ensures the offers are available when the customer schedules the work in their capital plan, but customers are made aware that the program offers are subject to change.

249.3 Does FBC incentivize its staff, contractors and third party providers, (for example, through bonuses, commissions) to support the DSM objective? If no, please explain why not. If yes, please describe.

Please include in your response whether FBC incentivize its staff, contractors and third party providers to: (i) reduce DSM selling costs, (ii) bring forward ideas to change existing program design/selling techniques in order to increase DSM sales; (iii) bring forward ideas for potential new DSM products/services; and/or (iv) sell more DSM.

Response:

All FBC Management and Exempt staff are eligible for the Company's short-term incentive program, and PowerSense Management and Exempt staff have the DSM program targets (savings and budget) written into their short-term performance objectives.

FBC has incented third party contractors with commissions (the more work done, the more money paid). It has not provided bonuses.

FBC has also provided "spiffs" (small selling commissions) to retailers to promote Energy Star electronics.

PowerSense staff receives the monthly internal reports of the kWh saved and program costs YTD, and largely take ownership of the annual program targets.

FBC regularly issues Requests for Proposals and Tender Calls to contractors to provide service delivery work. The intention of competitive bids is to reduce costs as much as possible while providing the high quality service needed.

FBC recently issued Requests for Quotes to certified energy assessors to provide home energy assessments for the Energy Diet programs. An RFQ for this service had never been done in BC before. By combining geographic efficiencies to reduce travel costs, minimum volume guarantees, and one service delivery agent, FBC was able to reduce the costs to customers significantly from approximately $150 to $60 per assessment.

250.0 Reference: BC Energy Plan, p. 5, Exhibit B-1-1, Appendix H-2, Semi Annual DSM Report 2012, p. 3

Coordination with other agencies

The BC Energy Plan states: "Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia." (p. 5)

FBC describes on page 3 of Appendix H-2 to the filing a number of new dual-fuel programs where FBC has worked together with the FU EEC team.

250.1 How does FBC coordinate with providers of other DSM programs (including BC Hydro, FEU, LiveSmart) in ensuring that a coordinated approach is undertaken in (i) program development and (ii) incorporating feedback from existing programs to better tailor program design?

Response:

FBC works closely with BC Hydro, FEU and the BC Ministry of Energy and Mines (MEM) to coordinate program offers, for example the LiveSmart BC Home Retrofit program.

FBC adapted its Product Rebate portal, an on-line portal that allows commercial customers to apply for commercial prescriptive measure incentives, to include FEU gas measures in the SST. FEU has adopted and expanded the portal which is renamed the Energy Rebate Centre (ERC). The intention is to expand the ERC to include all current residential prescriptive offers (gas & electric) province-wide.

FBC is a key member of the BC "Utility Partners" partnership and works collaboratively to conduct market and evaluation research, create program policy and offer consistent rebate/incentive offers. The Utility Partners have taken on the LiveSmart BC incentive offers, and are positioned to manage the entire program if the MEM supporting funding (for energy assessments) is terminated.

By jointly funding the BC Hydro M&E review of the LiveSmart BC residential program, FBC will be able to incorporate the reports' findings into program design changes.

250.2 Are FBC DSM activities are part of a shared service department within the combined Fortis electricity/gas business group?

Response:

Not at this time. Structurally, DSM is part of the FBC customer service department, whereas EEC is part of the FEU Energy Solutions and External Relations group.

From a resource allocation perspective, FBC's program delivery staff are within the COPE bargaining unit whilst FEU's staff are exempt, with the exception of the FEU's Street Team, which undertakes outreach to the general public. Under the COPE contract, exempt staff may not assume responsibilities or roles of bargaining unit staff. The program design staff, while exempt, work closely together on activities within the Shared Service Territory. Wherever possible, as part of the FortisBC integration, DSM and EEC program offers have been aligned and are designed to be customer-facing i.e. offered as "one program" so customers only see a single seamless "combined" program in the Shared Service Territory. An example is the PRP/ERC (please refer to the response to BCUC IR 1.250.1).

251.0 Reference: Exhibit A2-11 Energy Provider Delivered Energy Efficiency, p. 89

Use of the Market to Discover and Deliver Cost Effective EEC

Exhibit A2-11, a 2013 International Energy Agency report on Energy Provider-Delivered Energy Efficiency states: [63]

> "Market-based instruments (MBI) such as White Certificates (WhC) are a common feature of many EEO schemes" (Exhibit A2-11, p. 33)

> "The Block Bidding Programme is a sealed-bid auction designed to allow project developers to offer energy saving projects that increase total savings above levels expected from energy provider-administered programmes. The programme has been recognized by the New York state regulator as a model for other investor-owned utilities." (Exhibit A2-11, p. 89)

251.1 Does FBC partner with any social agencies in the delivery of its low-income DSM programs? Please explain why/why not.

Response:

Yes, FBC has partnered with the BCNPHA (BC Non-Profit Housing Association) over the past two years to do a direct installation program for common and in-suite areas in BCNPHA housing stock. FBC has also worked with all of the food banks and several other low-income service delivery organizations to distribute energy savings kits and energy efficiency lighting.

251.2 What process would FBC follow if an individual or company brought forward an idea for a possible DSM project, for example, a school education program? Please explain if and how this idea would be evaluated.

Response:

FBC has adopted an evaluation matrix to determine possible sponsorship of educational opportunities presented to it. The matrix evaluates relevancy, relative cost of exposure, target audience, and sponsor profile and fit.

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[63] http://www.iea.org/publications/insights/EnergyProviderDeliveredEnergyEfficiency_WEB.pdf

251.2.1 If FBC did not wish to pursue the idea brought forward, what process would be available to the individual/company to challenge this?

Response:

FBC's practice is to provide reasons to the individual/company (e.g. poor opportunity, resource constraints or perhaps a competing program) for the Company's decision, and work with the customer to find a mutually acceptable solution. If such a solution could not be found and the customer is not satisfied with the outcome, the issue would be escalated within FortisBC.

251.3 What process, if any, does FBC use to actively solicit ideas from individuals and companies regarding potential cost-effective DSM programs?

Response:

There is no formal process; however ideas from customers or companies are forwarded by DSM program staff to DSM senior managers for consideration.

Please also refer to the response to BCSEA IR 1.1.4.

251.3.1 Please discuss the advantages/disadvantages of (i) a DSM 'standing offer program', where FBC agrees to purchase energy savings from third parties at a specified c/kWh (similar to BC Hydro's Standing Offer Program) and (ii) a FBC 'reverse auction', where FBC invites DSM suppliers to bid to supply DSM, and awards contracts to the lowest bidder (similar to BC Hydro's Clean Energy Call).

Response:

(i) FBC believes its DSM programs are currently structured as "standing offers" in that the program incentives ($/unit and $/kWh) are available to all customers. Third parties, such as heating/cooling contractors, do promote the DSM program offers on this basis.

The Company has used third party service providers, selected through a competitive procurement process, for a number of DSM initiatives including the recently completed $7.3m FLIP program.

Disadvantages of having a third-party disseminate the FBC programs include: the third-party administrative cost and profit margins increases project costs; trust issues (perception of carpet-baggers); the additional due diligence required to verify aggregated energy savings; the possibility of “cream skimming” of low-hanging measures; and the lack of a long-term customer relationship that can be nurtured over time to harvest additional energy savings.

(ii) FBC believes its service area is not large enough by itself to attract sufficient DSM suppliers to hold a robust auction. Also the disadvantages listed in part (i) of this response will apply.

251.4 Please describe the delivery agents used by FBC to deliver DSM, and the process used to determine which services should be provided by a third party and to procure these services.

Response:

FBC delivers many of its programs directly through professionally trained and qualified internal staff.

However, when opportunities arise to provide additional DSM program services that fall outside of employees’ responsibilities, FBC has contracted the work out through RFP and tender procurement processes. Most recently, services provided by third party contractors included the FLIP (small commercial business direct install lighting retrofit), direct installation of EE measures for low-income housing (non-profit owned and market-based rental multi-family units), distribution of low-flow shower heads, home energy assessments for single-family homes, and consulting engineering reports for commercial customers.

251.4.1 Does FBC consider that it can generally deliver its DSM programs more cost effectively than LiveSmart or PowerSmart? Please explain why/why not.

Response:

The question does not specify what metrics should be used for comparison, and in any case FortisBC would have limited access to the information required to compare the programs requested.

FBC believes it delivers DSM programs cost-effectively and tailored to its customer base, as evidenced by a UCT levelized cost of $51/MWh in 2012.

Livesmart BC has not published any performance metrics, that FBC is aware of, with which to compare.

BC Hydro recently filed a summary report[64] of PowerSmart activities for Fiscal 2013. Table 4 provides a UCT of $18/MWh for programs, but this figure is not immediately comparable as it excludes capacity benefits (hence some program UCT's are negative) and is heavily weighted (65% of program savings) towards low cost industrial savings.

[64] BC Hydro PowerSmart Report on Demand-Side Management Activities for Fiscal 2013. dated August 30, 2013.

252.0 Reference: Exhibit B-1, Appendix I-1, p. 15

Residential Programs – DSM Plan overview

Commission Staff has compiled the following summary table on Residential DSM Programs for the period 2014-2018 from Table H-5 (p. 10 of Appendix H), Table H1-2a (p. 5 of Appendix H1) and information on pages 1-2 of Appendix H3.

DSM Plan 2014-2018 Residential Programs (Table H-5, page 10, Appendix H)	**Residential Program Expenditures and Savings (Tables H1-2a and H1-2b, p. 5, Appendix H1)**	**Residential Programs (pp. 1-2 of Appendix H3 on Monitoring and Evaluation)**
Home Improvement (Building Envelop) Program	Building Envelop	Home Improvement Program • Building Envelop measures
Heat Pump Program	Heat Pumps	ENERGY STAR Air Source and Ground Source Heat Pump Program • TLC Heat Pump Tune-up measure
ENERGY STAR ® Water Heater Program	Water Heating	**n/a**
Water Savers (Low-Flow Fixtures)	**n/a**	**n/a**
n/a	**n/a**	ENERGY STAR Appliance Rebate Program
ENERGY STAR ® Residential Lighting	Lighting	ENERGY STAR Lighting Rebate Program
New Home Program	New Home	New Home Program • EnerGuide Evaluations • Performance Path: EnerGuide 80/85 • Prescriptive Path: Insulation (SIP and ICF)
Financing Pilot	**n/a**	On-Bill Financing – (Renovation for Efficiency Loan Program)
Low Income (p. 5 of Appendix H) • Energy Savings Kit Program • Direct Installation Program • Energy Conservation Assistance Program	Low Income & Rental	Low Income/Rental Programs • Energy Savings Kit Program • Direct Installation Lighting Program

252.1 Please reconcile the information on residential DSM programs provided in these three tables/documents (differences are bolded in the table above).

Response:

Please see reconciled information on residential DSM programs below:

DSM Plan 2014-2018 Residential Programs (Table H-5, page 10, Appendix H)	**Residential Program Expenditures and Savings (Tables H1-2a and H1-2b, p. 5, Appendix H1)**	**Residential Programs (pp. 1-2 of Appendix H3 on Monitoring and Evaluation)**
Home Improvement (Building Envelop) Program	Building Envelop	Home Improvement Program • Building Envelop measures
Heat Pump Program	Heat Pumps	ENERGY STAR Air Source and Ground Source Heat Pump Program • TLC Heat Pump Tune-up measure
ENERGY STAR ® Water Heater Program	Water Heating	**For M&E purposes, the ENERGY STAR® Water Heater Program is considered part of the Home Improvement Program.**
Water Savers (Low-Flow Fixtures)	**n/a – Water Savers (Low-Flow Fixtures) are included in the budget for Water Heating.**	**For M&E purposes, Water Savers (Low-Flow Fixtures) are considered part of the Home Improvement Program.**
The ENERGY STAR® Appliance Rebate Program is not included in the 2014-2018 DSM Plan. The Appliance program is under evaluation in 2013, and the evaluation indicated for 2015 in the M&E plan will not be completed.	**The ENERGY STAR® Appliance Rebate Program is not included in the 2014-2018 DSM Plan. The Appliance program is under evaluation in 2013, and the evaluation indicated for 2015 in the M&E plan will not be completed.**	ENERGY STAR Appliance Rebate Program
ENERGY STAR ® Residential Lighting	Lighting	ENERGY STAR Lighting Rebate Program
New Home Program	New Home	New Home Program • EnerGuide Evaluations • Performance Path: EnerGuide 80/85 • Prescriptive Path: Insulation (SIP and ICF)

DSM Plan 2014-2018 Residential Programs (Table H-5, page 10, Appendix H)	Residential Program Expenditures and Savings (Tables H1-2a and H1-2b, p. 5, Appendix H1)	Residential Programs (pp. 1-2 of Appendix H3 on Monitoring and Evaluation)
Financing Pilot	**The On-Bill Financing Pilot Program costs are not part of the DSM Budget. These costs are part of a non-rate base deferred account, Exhibit B-1, Section E, Table 1-B, pp. 285-288.**	On-Bill Financing – (Renovation for Efficiency Loan Program)
Low Income (p. 5 of Appendix H) • Energy Savings Kit Program • Direct Installation Program • Energy Conservation Assistance Program	Low Income & Rental	Low Income/Rental Programs • Energy Savings Kit Program • Direct Installation Lighting Program

252.1.1 In particular, please provide the expenditures or savings expected from the Water Savers, ENERGY STAR Appliance Rebate or Financing Pilot programs.

Response:

The following table shows plan savings expected from the Water Savers, ENERGY STAR Appliance Rebate or Financing Pilot as per our DSM plan.

Program	Plan (kWh/yr)	Plan ($/yr)	Notes
Water Savers	366,000	$53,000	Incentive costs only
Residential Appliances	0	0	The 2014-2018 DSM Plan does not include an appliance program.
On-Bill Financing Pilot*	96,000**	$33,664	For 2014 only, as pilot ends in Dec 31st.

* *OBF costs are in a separate deferral account as per BCUC directive.*

** *OBF savings are not counted separately, but are included in Building Envelope and Heat Pump program plan savings.*

252.1.2 Please provide the monitoring and evaluation schedule for the Water Heater, Water Savers and ECAP programs.

Response:

As indicated in the response to BCUC IR 1.252.1, the Water Heater and Water Savers programs are considered part of the Home Improvement Program for M&E purposes. Therefore, they will be evaluated as part of the Home Improvement Program Evaluation that is scheduled over 2014 and 2015 (see Table 9, Appendix H3).

The ECAP program will likely be evaluated in collaboration with the utility partners involved (BC Hydro and FEU). The date of the evaluation will depend on the program launch date within the shared service territory and the evaluation schedules of the utility partners.

On page 7 of Appendix H1, FBC notes that the residential behavioural program will continue using economic channels.

252.2 Please explain why the behavioural program is the only program expected to be reviewed through market activities (Table 9 on page 20 of Appendix H3) in the DSM M&E Plan?

Response:

The DSM M&E plan indicates the behavioural program for evaluation through market activities because the intent at the time the DSM M&E Plan was completed was to conduct a behavioural baseline study. Other programs will have a market perspective informed by interviews with participants and trade allies (e.g. contractors) etc.

252.2.1 Could behavioural programs also be assessed with process and impact evaluations? If not, why not.

Response:

Yes, behavioural programs could also be assessed with process and impact evaluations.

253.0 Reference: Exhibit B-1, Appendix I-1, p. 41

Commercial Programs – EEC Plan overview

Commission Staff has compiled the following summary table on Commercial DSM Programs for the period 2014-2018 from Table H-5 (p. 10 of Appendix H), Tables H1-3a and H1-3b (p. 8 of Appendix H1) and information on page 2 of Appendix H3.

DSM Plan 2014-2018 Commercial Programs (Table H-5, page 10, Appendix H)	Commercial Program Expenditures and Savings (Tables H1-3a and H1-3b, p. 8, Appendix H1)	Commercial Programs (p. 2 of Appendix H3 on Monitoring and Evaluation)
Commercial Lighting Program	Lighting	Commercial Lighting Program (Custom)
Building & Process Improvement Program	BIP	Building Improvement Program • New Facility Assessment and Incentives Program • Retrofit Audit and Incentives Program • Building Optimization Program
Product Rebate Program	**n/a**	Product Rebate Program • Lighting and equipment measures
Commercial Energy Assessment Program (CEAP)	**n/a**	**n/a**
n/a	Irrigation	Irrigation /audit and Pump Efficiency Program

253.1 Please reconcile the information on commercial DSM programs provided in these three tables/documents (differences are bolded in the table above).

Response:

Information on commercial DSM programs is reconciled in the table below:

DSM Plan 2014-2018 Commercial Programs (Table H-5, page 10, Appendix H)	Commercial Program Expenditures and Savings (Tables H1-3a and H1-3b, p. 8, Appendix H1)	Commercial Programs (p. 2 of Appendix H3 on Monitoring and Evaluation)
Commercial Lighting Program	Lighting	Commercial Lighting Program (Custom)

DSM Plan 2014-2018 Commercial Programs (Table H-5, page 10, Appendix H)	Commercial Program Expenditures and Savings (Tables H1-3a and H1-3b, p. 8, Appendix H1)	Commercial Programs (p. 2 of Appendix H3 on Monitoring and Evaluation)
Building & Process Improvement Program	BIP	Building Improvement Program • New Facility Assessment and Incentives Program • Retrofit Audit and Incentives Program • Building Optimization Program
Product Rebate Program	**The Product Rebate Program is included in Lighting and Building Improvement Program (BIP) in Tables H1-3a and H1-3b, p. 8, Appendix H1.**	Product Rebate Program • Lighting and equipment measures
Commercial Energy Assessment Program (CEAP)	**CEAP is included in BIP in Tables H1-3a and H1-3b, p. 8, Appendix H1.**	**For M&E purposes, CEAP is considered part of the Building Improvement Program.**
Irrigation omitted in error.	Irrigation	Irrigation /audit and Pump Efficiency Program

253.1.1 In particular, please provide the expenditures or savings expected from the Product Rebate and CEAP programs.

<u>Response:</u>

The Product Rebate Program is not a stand-alone program, it is better described as a "portal" in which customers can readily access a host of prescriptive or product rebates are offered for measures under the Commercial Lighting and Building Improvement Programs. As stated in response BCUC IR 1.253.1, the expenditures and savings expected from the Product Rebate Program are included in both the Lighting and Building Improvement Programs (BIP) in Tables H1-3a and H1-3b, p. 8, Appendix H1.

The expenditures and savings expected from CEAP are included in BIP in Tables H1-3a and H1-3b, p. 8, Appendix H1.

253.1.2 Please provide the monitoring and evaluation schedule for the CEAP program.

Response:

A process review of the Commercial Energy Assessment Program (CEAP) will be undertaken in late 2014 or early 2015, and CEAP will be included in the scope of a comprehensive BIP program evaluation in the next M&E Plan cycle, likely in 2016.

253.1.3 Please explain why the Irrigation DSM program is not listed in Table H-5 of Appendix H?

Response:

Irrigation was omitted, in error, from Table H-5.

254.0 Reference: Exhibit B-1, Appendix I-1, p. 63

Industrial Programs – EEC Plan overview

Commission Staff has compiled the following summary table on Industrial DSM Programs for the period 2014-2018 from Table H-5 (p. 10 of Appendix H), Tables H1-4a and H1-4b (p. 9 of Appendix H1) and information on page 2 of Appendix H3.

DSM Plan 2014-2018 Industrial Programs (Table H-5, page 10, Appendix H)	Industrial Program Expenditures and Savings (Tables H1-4a and H1-4b, p. 9, Appendix H1)	Industrial Programs (p. 2 of Appendix H3 on Monitoring and Evaluation)
Industrial Efficiency Program	Industrial Efficiency	Industrial Efficiency Program • Industrial Audit and Incentives Program
n/a	**n/a**	Industrial EMIS (Energy Management Information System)

254.1 Please reconcile the information on industrial DSM programs provided in these three tables/documents (differences are bolded in the table above).

Response:

Due to limited DSM potential, and the small pool of eligible customers, the industrial EMIS offer was dropped as a stand-alone item in the 2014-18 DSM Plan, thus does not appear in the tables referenced. If a customer was interested in pursuing this measure, they could apply through the generic Industrial Efficiency program.

254.1.1 In particular, please provide the expenditures or savings expected from the Industrial EMIS program.

Response:

Please refer to the response to BCUC IR 1.254.1.

255.0 Reference: Exhibit B-1-1, Appendix H2, p. 2

Program Process Improvement

FBC states that "PowerSense received approval from the [Commission] in Order G-110-12 to procure an end-to-end DSM business process management platform. Business case scenarios and process mapping were undertaken to define the requirements for the new system."

255.1 Please provide the page number where this approval can be found in Order G-110-12.

Response:

FBC applied for approval of the PowerSense end-to-end DSM business process management platform in its 2012-2013 Capital Expenditure Plan (Section 6.6.5, PowerSense DSM Reporting Software). The project was approved as part of the category General Plant, which is addressed on page 102 of the Decision accompanying Order G-110-12.

255.2 Please explain what an end-to-end DSM business process management platform is.

Response:

The new DSM system (referred to as PowerSense DSM Reporting Software in the 2012-2013 Capital Expenditure Plan) is software that starts at the customer end (rebate centre portal to apply for programs on-line) through the internal business processes (vetting & approving the application, including M&V) to fulfilment (incentive cheque issue or bill credit). It is the system of record, producing standardized and ad hoc reports.

255.3 Please report on the progress to date to procure and implement this new system.

Response:

The project Business Case leveraging the procurement and process work previously performed by the FEU, was completed and signed off. The Project Charter and plan with high-level requirements are complete. DSM business processes were identified, and programs/reports are prioritized. A software vendor has been selected and the Master Service Agreement awaits their acceptance. A purchase order will be issued shortly and the implementation phase will begin. This project should be operational in the 1st quarter of 2014.

256.0 Reference: Exhibit B-1-1, Appendix H2, p. 2

New Programs

FBC states that "[t]he Reduce Your Use program was launched in mid-year to coincide with the introduction of the inclining block Residential Conservation Rate (RCR)."

256.1 Please describe the Reduce Your Use program and discuss whether this program has been successful since its launch, scheduled to coincide with the introduction of the RCR.

Response:

The Reduce Your Use program has been modestly successful. In 2012, 115 customers applied and received rebates for energy assessments. In 2013, FBC provided rebates to 65 customers. (In each year 5 low-income customers received free energy assessments.)

In May 2013, FBC launched the Kootenay Energy Diet and in September the Okanagan Energy Diet. As the Energy Diets provide subsidized energy assessments as well as the direct installation of household EE measures, providing a more comprehensive successor program to Reduce Your Use.

256.2 Given customer complaints related to the RCR rate, please explain why Reduce Your Use program is not part of the proposed 2014-2018 DSM Plan.

Response:

Please refer to the response to BCUC IR 1.256.1. The Energy Diet program is a more comprehensive successor to the Reduce Your Use program.

FBC states that "Customers access the [Product Rebate] program via a custom-built online application form, which assists in addressing the issue of customer attribution... The Product Rebate Program replaces the Wholesale Lighting Program, which was successful but had issues with customer attribution." (Emphasis added)

256.3 Please explain what the issue of customer attribution is generally. Please also discuss how the Product Rebate Program was designed to address this issue.

Response:

The issue is for the DSM program to get attribution for the DSM incentive given to the customer. In the case of the Wholesale Lighting Program, some customers were not aware that they had received a PowerSense rebate as it was built into their invoice. In the evaluation of this program this issue affected the free ridership rate. In the Product Rebate Program, the customer fills out an online form to apply for the incentive, which helps improve program attribution.

257.0 Reference: Exhibit B-1-1, Appendix H2, pp. 4-5

PowerSense Programs Offered in 2012

Tables 1 and 2 provide a list of residential, commercial and industrial programs and measures.

257.1 Please provide the definition for 'program' and 'measure'. For Tables 1 and 2, please also indicate which ones are the programs and which ones are the measures.

Response:

For the PowerSense DSM Portfolio, the term 'program' refers to a vehicle used to provide information to customers and/or to provide customer access to incentives for an individual measure or a group of measures that are related by the targeted customer type, the targeted energy end-use or marketing method.

In the PowerSense DSM portfolio, a 'measure' reduces electrical consumption and may consist of an energy-efficient product, device, piece of equipment, system or building or process design.

In some cases a single measure may be marketed under more than one program to make it more accessible to customers.

The revised tables below indicate whether an item is a program or measure.

Table 1 (Revised)

Program and Measures	Program or Measure
Energy Star Appliances	Program
Energy Star Electronics	Program
Energy Star Retail Lighting Rebate	Program
Heat Pump (Air Source and Geo-Exchange)	Program
TLC Heat Pump Maintenance	Measure
New Home ▪ Performance [path] • EnerGuide Ratings 80/85 ▪ Prescriptive [path] • Lighting • Appliances • Insulation • Heat pumps • NEW: Fireplaces (gas) • NEW: Hot water (gas)	New Home is a program (with two paths). Sub-bullets are measures.

Program and Measures	Program or Measure
Home Improvement (Retro-fit) • Windows and doors • Lighting • Appliances • Insulation • Heat pumps • Heat pump loan option • NEW: Fireplaces (gas) • NEW: Hot water (gas)	Home Improvement is a program. Bullets are measures.
LiveSmart BC (Retro-fit) • Windows and doors • Insulation • Heat pumps • Hot water	LiveSmart BC is a program. Bullets are measures.
Reduce Your Use (energy assessments)	Measure
On-Bill Financing	Program
Low Income – Direct Installation Lighting	Program - Measure
Low Income – Energy Savings Kits	Program- Measure
Rental and Low-Income Housing	Program
Supporting Initiatives	Program
Contractor program	Program
WaterSavers (Tap by Tap)	Program

Table 2 (Revised)

Program and Measures	Program or Measure
Product Rebate Program • Lighting • Pumps and fans • Compressors • Refrigeration • HVAC • Boilers (gas) • Water Heaters (gas)	Product Rebate Program is a program. Bullets are measures.
Building Improvement – New	Program
Building Improvement – Retro-fit	Program
Building Optimization	Program
Partners in Energy [Efficiency]	Program

Program and Measures	Program or Measure
Energy Efficiency Studies	Measure available with custom commercial projects.
Industrial Efficiency	Program
Irrigation Pumping	Program
Green Motors (motor rewinds)	Green Motors is a program. Motor rewind is a measure.

257.2 Please explain why the Reduce Your Use and Contractor Programs, which were introduced in 2012, are no longer part of the DSM Plan for 2014-2018, as per Table H-5 on page 10 of Appendix H.

Response:

Reduce Your Use has had limited take-up by customers, and thus was discontinued. Please also refer to the response to BCUC IR 1.256.1.

The Contractor program will continue in the form of a customer referral list on the FortisBC public website, but the contractor co-op advertising offer is discontinued.

257.3 Please provide details on the rental and low-income housing program that was in the design phase in 2012. Has this program been implemented since then? Please discuss.

Response:

In 2012, the intention was to complete the direct installation of EE measures for BCNPHA (BC Non-Profit Housing Association) multi-family housing. That project was completed in 2013. The distribution of energy savings kits continued as well.

A pilot project to introduce free walk-through energy assessments and direct installation of household EE measures for market-based multi-unit rental housing was started in August 2013. If successful this initiative will be expanded to other parts of the FBC service area.

The plan to partner with BC Hydro and FEU to deliver a province-wide, revamped Energy Conservation Assistance Program is underway and should be in market in late 2013 or early 2014.

257.4 Please explain why the Building Optimization, Partners in Energy, Energy Efficiency Studies and Green Motors programs, which were ongoing in 2012, are no longer part of the DSM Plan for 2014-2018, as per Table H-5 on page 10 of Appendix H.

Response:

The Building Optimization program was targeted at a handful of large institutional customers with multiple facilities. The key remaining institutional customer indicated they did not have the resources to proceed, so FBC removed the corresponding costs from its DSM Plan.

The Partners in Energy [Efficiency] is an ongoing initiative, and part of key account activities undertaken by DSM Technical Advisors.

Energy Efficiency Studies are ongoing, but relabelled as the Commercial Energy Assessment Program.

The Green Motors contract ended in 2013, and FBC will not be renewing it due to the high administration fees charged by the third-party administrator. FBC may add a prescriptive motor rewind incentive to the Product Rebate (Energy Rebate Centre) portal.

258.0 Reference: Exhibit B-1-1, Appendix H2, pp. 6-8

Energy Savings by Sector

In Table 4 – Residential Energy Savings, Fortis BC reports that the Low Income program and the New Home Program achieved 59 percent and 1155 percent of planned savings respectively. FortisBC also states that "[t]he New Home program exceeded Plan" and that "[c]ustomer participation in the New Home program continues to exceed plan expectations."

Regarding the Low Income program, FBC states that "in 2012, the Low Income program distributed approximately 950 Energy Saving Kits." (Exhibit B-1-1, Appendix H2, p. 7)

258.1 Please discuss the factors that have resulted in a significantly higher percentage of achieved savings for the New Home program or that have caused Fortis BC to significantly underestimate the savings that could be achieved by this program.

<u>Response:</u>

Factors include much higher customer participation than expected, with 81 projects compared to 26 in the plan. The Plan savings figures related only to the New Home "performance path" (homes that achieved an EnerGuide 80 rating), but also there were an additional 18 participants with prescriptive measure savings in this report line item.

258.2 Please discuss the factors that have resulted in a significantly lower percentage of achieved savings for the Low Income program. Is it because the 950 Energy Saving Kits distributed represent 59 percent of the number of kits that FBC expected to distribute to low income customers or because the kits themselves have resulted in less savings than expected?

<u>Response:</u>

The Energy Saving Kits provide only a portion of the savings in the Low Income program. The second phase of the Low Income Direct install program was a main factor in the reduced savings, due to a timing issue. Auditing for the second phase occurred in 2012, but installation did not occur until 2013, so the savings could not be claimed in 2012.

258.3 Please provide a concordance between (i) the residential programs listed in Table 4 and those listed in Table 1; (ii) the commercial programs listed in Table 5 and those listed in Table 2 and (iii) the industrial programs listed in Table 6 and those listed in Table 2.

Response:

The revised tables below provide the concordance between Table 1 and Table 4 and Table 2 and Tables 5 and 6.

Table 1 (Revised)

Program and Measures	Corresponding line item in Table 4
Energy Star Appliances	Home Improvement Program
Energy Star Electronics	Home Improvement Program
Energy Star Retail Lighting Rebate	Residential Lighting
Heat Pump (Air Source and Geo-Exchange)	Heat Pumps
TLC Heat Pump Maintenance	Heat Pumps
New Home ▪ Performance • EnerGuide Ratings 80/85 ▪ Prescriptive • Lighting • Appliances • Insulation • Heat pumps • NEW: Fireplaces (gas) • NEW: Hot water (gas)	New Home Program (unless otherwise noted) Lighting -> Residential Lighting Appliances -> Home Improvement Program Heat Pumps -> Heat Pumps Gas measures are not included in Table 4
Home Improvement (Retro-fit) • Windows and doors • Lighting • Appliances • Insulation • Heat pumps • Heat pump loan option • NEW: Fireplaces (gas) • NEW: Hot water (gas)	Home Improvement Program (unless otherwise noted) Lighting -> Residential Lighting Heat Pumps and loan option -> Heat Pumps Gas measures are not included in Table 4

Program and Measures	Corresponding line item in Table 4
LiveSmart BC (Retro-fit) • Windows and doors • Insulation • Heat pumps • Hot water	Home Improvement Program (unless otherwise noted) Heat Pumps -> Heat Pumps
Reduce Your Use (energy assessments)	Home Improvement Program
On-Bill Financing	Home Improvement Program
Low Income – Direct Installation Lighting	Low Income
Low Income – Energy Savings Kits	Low Income
Rental and Low-Income Housing	Low Income
Supporting Initiatives	n/a
Contractor program	n/a
WaterSavers (Tap by Tap)	Home Improvement Program

Table 2 (Revised)

Program and Measures	Corresponding line item in Tables 5 and 6
Product Rebate Program • Lighting • Pumps and fans • Compressors • Refrigeration • HVAC • Boilers (gas) • Water Heaters (gas)	Building and Process Improvement, unless otherwise noted. Lighting -> Lighting Gas measures are not included in Table 5
Building Improvement – New	Building and Process Improvement
Building Improvement – Retro-fit	Building and Process Improvement
Building Optimization	Building and Process Improvement
Partners in Energy	n/a
Energy Efficiency Studies	Lighting; Building and Process Improvement; Water Handling and Infrastructure; Industrial Efficiency
Industrial Efficiency	Industrial Efficiency; Integrated EMIS
Irrigation Pumping	Water Handling and Infrastructure
Green Motors (motor rewinds)	Industrial Efficiency

258.4 Please provide details of the district heating system project at a post-secondary educational institution in the Okanagan that resulted in 0.6 GWh of savings. Is this project a standard district energy system connecting multiple buildings and multiple customers? What are the primary energy source for this system and the back-up/peaking energy source?

Response:

This project connects multiple buildings that are owned by the same customer. The primary energy source for this system is geo-exchange and the back-up/peaking energy source is natural gas. The savings are from reduced pumping requirements as the project converted the geoexchange source from open-loop to closed-loop.

259.0 Reference: Exhibit B-1-1, Appendix H2, pp. 6-8

Program costs by Sector

259.1 Please provide a concordance between (i) the residential programs listed in Table 9 and those listed in Table 1; (ii) the commercial programs listed in Table 10 and those listed in Table 2; and (iii) industrial programs listed in Table 11 and those listed in Table 2.

Response:

Please refer to the response to BCUC IR 1.258.3. In the indicated response, Table 4 corresponds to Table 9, Table 5 corresponds to Table 10, and Table 6 corresponds to Table 11.

260.0 Reference: Exhibit B-1-1, Appendix H-2, 2014-2018 DSM Plan, Appendix H-2, FortisBC Semi-Annual DSM Report for December31, 2013

Data Analysis of EEC Actual and Forest Results

260.1 Please complete the following table for 2012 (actual), 2014 and 2018. Please explain any significant variances.

	Residential	Commercial	Industrial	Total
Number of Customers				
Number of customers as a % of FEU total				
Total GWh sold to these customers				
GWh sold as a % of total GWh sold to all customers.				
EEC budget for this customer class				
EEC budget above as a % of total EEC budget				

Response:

Tables 1 – 3 provide the requested information. The percentages for each sector do not vary significantly over time.

Table 1

2012 (actual)	Residential	Commercial	Industrial	Total
Number of Customers*	99,228	14,641	39	113,908
Number of customers as a % of FBC total*	87%	13%	0.03%	100%
Total GWh sold to these customers*	1,220	732	291	2,243
GWh sold as a % of total GWh sold to all customers.*	54%	33%	13%	100%
PowerSense budget for this customer class ($)	2,564,000	3,020,000	173,000	5,757,000
PowerSense budget above as a % of total PowerSense budget	45%	52%	3%	100%

** These totals are for direct customers and do not include Wholesale customers or GWh sold to Wholesale Customers.*

Table 2

2014 (Forecast)	Residential	Commercial	Industrial	Total
Number of Customers*	113,589	16,680	48	130,317
Number of customers as a % of FBC total*	87%	13%	0.04%	100%
Total GWh sold to these customers*	1,402	867	389	2,658
GWh sold as a % of total GWh sold to all customers.*	53%	33%	15%	100%
PowerSense budget for this customer class ($)	1,037,000	1,134,000	148,000	2,319,000
PowerSense budget above as a % of total PowerSense budget	45%	49%	6%	100%

** These totals are for direct customers and do not include Wholesale customers or GWh sold to Wholesale Customers.*

Table 3

2018 (Forecast)	Residential	Commercial	Industrial	Total
Number of Customers*	117,600	17,712	48	135,360
Number of customers as a % of FBC total*	87%	13%	0.04%	100%
Total GWh sold to these customers*	1,422	914	388	2,724
GWh sold as a % of total GWh sold to all customers.*	52%	34%	14%	100%
PowerSense budget for this customer class ($)	1,024,000	1,256,000	156,000	2,436,000
PowerSense budget above as a % of total PowerSense budget	42%	52%	6%	100%

** These totals are for direct customers and do not include Wholesale customers or GWh sold to Wholesale Customers.*

260.2 Please complete the following table for 2012 (actual), 2014 and 2018.

Program	Free-rider %	Spillover %	Non-energy benefits (% of total benefit)	Lifespan of asset	Persistence of savings assumed
_______ Program *(Fill in for each program, with sub-totals by customer class)*					

Response:

2012 (Actual) Program	Free-rider %	Spillover %	Non-energy benefits (% of total MTRC benefits) *	Lifespan of asset	Persistence of savings assumed
Residential Programs					
Home Improvement	0	0	1%	20	
Low Income	0	0	23%**	5	
Residential Lighting	9	0	-	5	
Heat Pumps	43	0	13%	17	
New Home Program	0	0	-	30	
Residential Total	**N/A**	**N/A**	**5%**	**N/A**	**100%**
Commercial Programs					
Lighting	28	0	-	12	
Building and Process Improvement	23	4	-	20	
Water Handling Infrastructure	0	0	-	15	
Commercial Total	**N/A**	**N/A**	**-**	**N/A**	**100%**
Industrial Programs					
Industrial Efficiency	12	0	-	10	
Integrated EMIS	12	0	-	10	
Industrial Total	**N/A**	**N/A**	**-**	**N/A**	**100%**

** Non-energy benefits are only applied to the measures that required MTRC lift in the 2012 Plan.*
*** Represents a 30% increase of non-MTRC benefits as per DSM regulation.*

For the 2014 – 2018 Plan the following conditions applied:

- Free-rider and Spillover estimates are built into the measure "net" unit savings,
- Non-energy benefit of 15% is applied to measures that require MTRC,
- Non-energy benefit of 30% is applied to Low Income measures,
- Lifespan of assets are in Exhibit B-1-1, Appendix H, Table H-6, p.18,
- 100% savings persistence is assumed.

261.0 Reference: Exhibit B-1, Appendix I, pp. 6, 7

Specified DSM Measures/Prescribed Undertakings

261.1 Please provide a mapping of FBC's EEC projects, together with their 2014-2018 budgets, and TRC/mTRC and UCT forecasts, which meet the following definitions:

- A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption.
- A demand-side measure intended specifically to improve the energy efficiency of rental accommodations.
- An education program for students enrolled in schools in the utility's service area.
- An education program for students enrolled in post-secondary institutions in the utility's service area.

Response:

2014-2018 demand-side measures intended specifically to assist residents of low income and rental households to reduce their energy consumption:

Program	2014				2015	2016	2017	2018
	Plan Cost	TRC	TRC incl mTRC	UCT	Plan Cost	Plan Cost	Plan Cost	Plan Cost
	$(000s)	B/C ratio			$(000s)	$(000s)	$(000s)	$(000s)
Low Income & Rental	242	0.8	1.4	1.0	281	206	208	210

2014-2018 education programs for students enrolled in schools/post-secondary institutions in the FEU's service area:

Component	2014 Plan $(000s)	2015 Plan $(000s)	2016 Plan $(000s)	2017 Plan $(000s)	2018 Plan $(000s)
Trades Training	10	10	10	10	10
Education (schools)	50	50	50	50	50
Supporting Initiatives sub-Total	**60**	**60**	**60**	**60**	**60**

262.0 Reference: Exhibit B-1-1, Section 5.3, p. 11

Plan Flexibility and Adjustment

FBC requests that it be permitted to launch new programs using a transfer of funds within an approved Program Area if: "this new program meets with the DSM Regulation, benefit/cost test requirements, and has not been previously rejected by the Commission."

262.1 Since this proposal, if approved, would have FBC transfer money away from other approved programs into new programs, would FBC need to demonstrate that the new proposed programs would work better and be more cost-effective than the previous ones? What criteria would FBC use to demonstrate that this is the case?

Response:

FBC is proposing that the minimum requirement for such a transfer would be that the program to which funds are being transferred are as outlined above: namely that the program meets the stipulations of the DSM Regulation, benefit/cost test requirements and that it has not been previously rejected by the Commission.

Any new program would be introduced in order to respond to a market demand that has not been anticipated in drawing up the 2014-2018 DSM Plan. It may not be more cost-effective than the programs that have been put forward in the 2014-2018 DSM Plan; however if the overall portfolio remains cost-effective it should be allowed to proceed. There are many reasons why FortisBC may introduce new programs that may be less cost-effective than existing programs, including support of provincial initiatives with other utilities or addressing specific areas of customer interest.

It should also be noted that the proposal related to introducing new programs is different from the ongoing "tweaking" of existing programs, which may include the introduction of new measures, to optimize program results that FBC undertakes on an ongoing basis.

FBC would detail the new program and the factors supporting its introduction in the year-end Annual Report.

263.0 Reference: Exhibit B-1-1, Section 6.2.2, p. 15; Muncaster et al. (2012) [65]

Attribution of Savings from the Introduction of Regulation

FBC states that "[p]ursuant to this element of the DSM Regulation, the Company intends to attribute the benefit of savings from the introduction of codes and standards on a program-by-program basis where such an attribution can be supported. FBC is seeking the Commission's endorsement of the concept for reporting purposes."

Muncaster *et al.* (2012) states on page 8-215:

"KEMA et al. estimated the effect of utility programs on a variety of California codes & standards, and found attributable savings to be 59% and 45% for annual electricity and natural gas savings respectively... Similarly, the Salt River Project in Arizona is allowed to claim up to 50 percent of savings from new building codes and appliance standards (Drexler 2012, 3).

In the new BC regulation savings can be claimed for programs that are run after a standard is announced or enacted, but before it comes into effect. <u>The BCUC is tasked with approving the attribution rate</u>. Attribution of savings from codes and standards is considered a part of the TRC rather than modified TRC (MTRC)..." (Emphasis added)

263.1 Please explain how FBC would calculate on a program-by-program basis the attribution rate of savings from the introduction of regulations.

<u>Response:</u>

At this time FBC does not contemplate claiming any savings from the introduction of codes and standards over the PBR period, thus it has not developed any methodologies for calculating and attributing energy savings.

263.2 The paper referenced above (part authored by FBC) states "the BCUC is tasked with approving the attribution rate", but FBC now states "FBC is seeking the Commission's endorsement of the concept for reporting purposes." Please explain the change in position.

[65] Muncaster, K., A. Pape-Salmon, S. Smith, M. Warren. *Adventures in Tweaking the TRC: Experiences from British Columbia*, 2012 ACEEE Summer Study on Energy Efficiency in Buildings

Response:

There is no change in position, intended or otherwise. Endorsement of the concept by the Commission simply means agreeing that Codes & Standards attribution represents valid savings. The methodology used to determine the attribution rate, and savings reported, would still be subject to the Commission's review.

263.3 Given that the estimated attribution rates of utility programs reported in the paper are significant and range between 45 and 59 percent, please explain why FBC believes that the Commission should not review and approve the method used by FBC to estimate a program's attribution rate in the future before it would be able to incorporate savings from the introduction of codes and standards into its reporting.

Response:

Please refer to the response to BCUC IR 1.263.2.

Codes & Standards attribution methodology will be a topic discussed with FBC's DSM Advisory Committee and with the FEU's EEC Advisory Group, both of which include Commission staff. The attribution rule(s) would then be subject to the Commission's review and endorsement by following an appropriate process before the Commission if required.

264.0 Reference: Exhibit B-1-1, Section 7.3, p. 17

Attribution Rules for Multi-Utility Programs

FBC states that "[g]oing forward, FBC will continue to work in developing more comprehensive attribution rules in cooperation with BC Hydro and the FEU Companies so that reporting of the benefits of combined programs is maximized while avoiding the potential for double-counting of energy savings."

264.1 If DSM programs become more integrated in the future across BC utilities, please explain why the current method of reporting energy savings between utilities to avoid double-counting would no longer work.

Response:

FBC disagrees as the current practice may well continue to work even if the complexity of combined programs increases. Inherently the FEU companies would claim natural gas savings, and the electric companies (FBC & BCH) would claim electric savings within their respective service areas.

In its 2012-13 RRA Decision the Commission directed FEU to further develop the methodologies, i.e. principles, of attribution in joint or integrated programs. FBC will participate in said development to ensure its interests are appropriately addressed.

264.2 What is FBC's timelines to develop these more comprehensive attribution rules? If the new rules are developed within the next five-year, does FBC plan to file them with the Commission for review before it would start using them? If not, why not.

Response:

The utilities plan to continue discussions on the topic of attribution of energy savings from combined programs over the upcoming year. There is no requirement in the DSM Regulation, in the Utilities Commission Act or in the Clean Energy Act for FBC to file attribution rules for review by the Commission. Such attribution rules would be a topic of discussion with FBC's stakeholder group, and with the FEU's Energy Efficiency and Conservation Advisory Group, both of which include Commission staff. If Commission staff felt at the time that it was necessary for the Commission to review the attribution rules developed, the Commission could issue a directive requiring FBC to make a submission on the matter.

265.0 Reference: Exhibit B-1-1, Section 2.4.2, p. 5, DSM Regulation, Section 3

Adequacy Pursuant to the DSM Regulation – Rental Accommodations

FBC states that "[a]ll programs in the Residential Energy Efficiency Program Area are available to rental properties. Some of the programs included in the Commercial Energy Efficiency Program Area are also available for use by, and actively promoted to, owners of rental accommodations."

Section 3 of the DSM Regulation requires that a demand-side measure intended specifically to improve the energy efficiency of rental accommodations be included in the DSM portfolio..."

265.1 Please explain why FBC did not include in its DSM Plan a DSM program intended specifically for rental accommodations as required in the DSM Regulation.

<u>Response:</u>

Presently, FBC is piloting a multi-family rental direct install (in-suite) and common area energy assessment pilot project, which is proving to be very successful. Based on that success, the intent is to continue the program into 2014 and beyond.

Note: the rental program budget is included within the low-income/rental program line item.

265.2 Since the DSM Regulation requires a utility to offer programs aimed specifically at rental accommodations, please explain how the Commission can be satisfied that FBC's DSM portfolio can be considered adequate for the purposes of section 44.1(8)(c) of the UCA.

<u>Response:</u>

Please refer to the responses to BCUC IRs 1.257.3 and 1.265.1.

Attachment 45.1

Electric Utility Rate Economics by Russell Caywood, Published by McGraw Hill 1972

3. COST OF ELECTRIC SERVICE

High investment results in a large part of costs being determined by number of customers and amount of load served; a smaller part of the cost is dependent on kilowatt-hours, or energy supplied. These cost elements can be described as follows:

a. Customer cost. Varies with number of customers served and includes investment charges and expenses relative to a portion of the general distribution system, service drop or other local connection facilities, metering equipment, meter reading, billing, and accounting.

b. Load or customer's demand cost. Varies with customer's load and includes investment charges and expenses in connection with generating plants, transmission lines, substations, and the part of the distribution system not included under *a.* The reason for this cost element can be illustrated by examining two customers with equal consumptions but different demands. Customer A has a load of 5 kilowatts which he operates 200 hours per month, making his monthly consumption 1,000 kilowatt-hours; Customer B has a load of 10 kilowatts which he operates 100 hours per month, giving a monthly use of 1,000 kilowatt-hours, the same as for Customer A. However, the cost of serving B is obviously greater than for A, because of the greater amount of equipment needed to supply the larger load.

c. Energy cost. Varies with the number of kilowatt-hours supplied to customers and is largely a fuel expense.

TABLE 14. ELECTRIC PLANT AND OPERATION AND MAINTENANCE ACCOUNTS, CDE GROUPING

Item	Plant accounts*	Operation and maintenance accounts*	C Customer cost	D Demand cost†	E Energy cost
Intangible plant	301–303	....	x	x	
Production plant	310–316, 320–325, 330–336, 340–346	500–507, 510–514, 517–525, 528–532, 535–557		x	x
Transmission plant					
Lines	350, 351, 354–359	560, 561, 563–568, 571–573		x	
Substations	352, 353	562, 569, 570		x	
Distribution plant					
Lines	360, 364–367, 371, 372	580, 581, 583, 584, 587–590, 593, 594, 598	x	x	
Substations	361–363	582, 591, 592		x	
Line transformers	368	595	x	x	
Services	369	....	x		
Meters	370	586, 597	x		
Street lighting	373	585, 596	x	x	
General plant	389–399	932	x	x	
Customer accounting & collecting expenses	....	901–905	x		
Sales promotion expenses	....	911–916	x		
Administrative & general expenses	....	920–931	x	(Revenue) x	

* Land accounts 350 and 360 can be allocated to lines and substations; supervision accounts 560, 568, 580, and 590 can be allocated to lines, substations, etc.

† When the load factor-coincidence relationship is used in distributing plant expense, some of these costs are classed "energy." See section on capacity allocation below.

Attachment 59.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 153.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 213.1

TOWERS WATSON

1100 Melville Street
Suite 1600
Vancouver, British Columbia
V6E 4A6

T +1 604 691 1000

towerswatson.com

February 28, 2013

Brett Henderson
Finance & Accounting
FortisBC Inc.
1975 Springfield Road
Kelowna, BC V1Y 7V7

PROJECTIONS OF FINANCIAL INFORMATION: 2014 – 2018

Dear Brett:

The purpose of this letter is to provide projected financial information with respect to the post-retirement benefit programs sponsored by FortisBC Inc. The Appendix provides the projected net benefit costs and employer contributions for FortisBC Inc. for 2013 through 2018. Details with respect to the projections are disclosed in the Appendix.

We have the following comments with respect to the projections:

1. In general, the current service costs are expected to increase with the passage of time as members receive increases in pay.

2. In general, the net interest cost (interest cost less expected return on assets) is expected to decline over time as past service contributions are remitted to the plans to improve the funded status.

3. In general, the amortization is expected to decline over time as unamortized amounts are amortized and as the 10% corridor increases in conjunction with expected increases in the PBO.

4. Based on the above, the general trend of a gradual decrease in the net benefit costs is to be expected.

Except as noted otherwise in the Appendix, the results presented in this letter are based on the data, assumptions, methods and plan provisions outlined in our report as at December 31, 2012 to determine accounting disclosure for FortisBC Inc.'s post-retirement benefit programs. Therefore, the descriptions of the data, assumptions, methods, plan provisions and limitations of the valuation report and its uses should be considered part of this letter. To our knowledge, our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Canada Inc.

Actuarial Opinion

In our opinion, the data on which the accounting information is based are sufficient and reliable for the purposes of this letter. The calculations made herein have been undertaken based on our understanding of Section 715 of the Financial Accounting Standards Board's Accounting Standards Codification ("ASC 715"), with which we are familiar, and FortisBC Inc.'s accounting policies, as consistently applied. The assumptions were selected by FortisBC Inc., following discussion with Towers Watson, and are in accordance with accepted actuarial practice in Canada. The discount rates used as at December 31, 2012 were based on AA corporate bond yields as at December 31, 2012 respectively. This letter has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

Please feel free to contact us if you have any questions.

Regards,

Stephen J. Butterfield, FCIA, FSA
Senior Consultant

Attachment

FortisBC Inc.

US GAAP (ASC 715) Projected Financial Information

	2013	2014	2015	2016	2017	2018
Total Pensions						
Pre-funded (accrued) benefit cost, beginning of year	2,849	314	2,741	6,349	9,144	11,329
Net benefit income (cost)	(8,923)	(8,159)	(7,196)	(6,224)	(5,376)	(4,650)
Employer contributions	6,388	10,586	10,804	9,019	7,561	6,922
Pre-funded (accrued) benefit cost, end of year	314	2,741	6,349	9,144	11,329	13,601
PRB Plan						
Pre-funded (accrued) benefit cost, beginning of year	(20,904)	(23,460)	(26,053)	(28,688)	(31,369)	(34,103)
Net benefit income (cost)	(3,213)	(3,314)	(3,423)	(3,541)	(3,668)	(3,804)
Employer contributions	657	721	788	860	934	1,014
Pre-funded (accrued) benefit cost, end of year	(23,460)	(26,053)	(28,688)	(31,369)	(34,103)	(36,893)

Notes:

1. All amounts are shown in thousands of Canadian dollars.
2. Actuarial assumptions during the projection period are assumed to be the same as those used for 2012 year-end reporting, including the following key assumptions:
   a. Discount rate = 4.0% per year
   b. Expected rate of return on assets = 6.5% per year
   c. Mortality = 95% of UP94 projected generationally
3. The projections assume no experience gains (losses) during the projection period.
4. Contributions to the registered pension plans have been estimated under the assumption that each of the plans will have actuarial valuations undertaken as at December 31, 2013 and December 31, 2016. The estimated contributions are primarily driven by the estimated solvency position which has been determined assuming a discount rate of 3.0% per year.
5. No allowance has been made for any possible changes to the plan provisions of the IBEW Plan or the COPE Plan.
6. The projections are based on membership data as at December 31, 2011.

Attachment 213.4

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 219.1

Attachment A – 2012 Commercial Industrial Market (n=275)

3M Canada Company
A&W Food Services of Canada Inc.
ALS Canada Ltd.
AMEC Inc.
ATCO I-Tek
Abbott Laboratories, Limited
Acuity Brands
Agfa Healthcare Canada
Agfa Inc.
Ainsworth Engineered Canada L. P.
Air Products Canada Ltd.
Akzo Nobel Canada Inc.
Alamos Gold Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Aluminerie Alouette Inc.
Amgen Canada Inc.
Amway Canada Corporation
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal Tubular Products - Automotive Division
Arrow Transportation Systems Inc.
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atlantic Poultry Incorporated
Atotech Canada Ltd.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BHP Billiton Canada Inc.
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barilla
Barrick Gold Corporation
Basell Canada Inc.
Baxter Corporation
The Bay
Bayer Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
Blue Mountain Resorts Limited
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Broan-NuTone Canada Inc.
Bruce Power L.P.
CAE Inc.
CGGVeritas
CHEP Canada Inc.
CKF Inc.
CNH America, LLC.
Cabot Canada Ltd.
Campbell Company of Canada
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
CannAmm Occupational Testing Services
Canon Canada Inc.
Canpotex Limited
Cargill Limited
Catalyst Paper Corporation
Caterpillar Logistics Services Canada Limited
Caterpillar of Canada Corporation
Caterpillar Tunneling Canada Corporation
Centerra Gold Inc.
Christie Digital Systems Inc.
Chubb Edwards
The Churchill Corporation
Compass Group Canada
Co-op Atlantic
Coty Canada
Country Ribbon Inc.
DP World Canada
DSM Nutritional Products Canada Inc.
Danfoss Inc.
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Detour Gold Corporation
Direct Energy Marketing Ltd.
Dow Chemical Canada Inc.
Dr. Oetker Ltd.
Dynaplast Extruco Inc.
EFW Radiology
E.I. du Pont Canada Company
EMD Serono Canada Inc.
ERCO Worldwide
EWOS Canada Ltd.
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Essar Steel Algoma Inc.
Finning Canada
Finning International

Attachment A – 2012 Commercial Industrial Market (n=275) (cont'd)

Fisher & Paykel Healthcare Inc.
G4S Cash Services (Canada) Ltd.
Gates Canada Inc.
General Kinetics Engineering Corporation
Gerdau Ameristeel
GlaxoSmithKline Inc.
Goldcorp Inc.
Golf Town
Graham & Brown
Grand & Toy
Griffith Laboratories Limited
Henkel Canada Corporation
Henry Schein Canada
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Home Outfitters
HudBay Minerals Inc.
Hudson's Bay Company
HumanWare
Hunter Dickinson Inc.
Huntsman Polyurethane
INEOS Canada Partnership
INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Janssen Inc.
John Deere Limited Canada
Johnson Matthey Ltd.
K+S Potash Canada
KGHM International Ltd.
K.I. Pembroke
KPMG MSLP
Kellogg Canada Inc.
Kemira Chemicals Canada Inc.
Kennametal Ltd.
Kimberly-Clark Corporation
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lantic Inc. - Rogers Sugar Division
Lego Systems, Inc.
Lehigh Hanson
Leo Pharma
LifeLabs
Linamar
Loblaw Companies Limited
Lotus Bakeries
Lowe's Companies, Inc.
Lundin Mining Corporation
MDA
MERSEN Canada Dn Ltd.
MERSEN Canada Toronto Inc.
Maidstone Bakeries Co.
Mainstream Canada Ltd.
McCoy Corporation
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Merz Pharma Canada
Methanex Corporation
Michelin North America (Canada) Inc.
Minas Basin Pulp & Power Co. Ltd.
The Minto Group
Mitsubishi Canada Limited
Montship Inc.
Morneau Shepell Inc.
The Mosaic Company
Navtech Systems Support Inc.
North American Palladium Ltd.
North Atlantic Refining
Northern Pulp Nova Scotia Corp.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Omicron
L'Oréal Canada Inc.
Otis Spunkmeyer Canada Limited
Outotec (Canada) Ltd.
OxyVinyls Canada Inc.
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Pan American Silver Corporation
Penske Truck Leasing
PepsiCo Canada
Phantom Mfg. (Int'l) Ltd.
Pharmascience Inc.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Potash Corporation of Saskatchewan Inc.
Praxair Canada Inc.
Procter & Gamble Inc.
Purdue Pharma
Randstad Canada
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rolls-Royce Canada Ltd.

Attachment A – 2012 Commercial Industrial Market (n=275) (cont'd)

Rothmans, Benson & Hedges Inc.
Runge Limited
Russel Metals Inc.
SABIC Innovative Plastics Canada Incorporated
SEMAFO inc.
SNC-Lavalin Group Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis
Saskatchewan Roughrider Football Club
Schneider Electric
Sears Canada Inc.
The Shaw Group Limited
Sherritt Coal
Shiseido (Canada) Inc.
Shore Gold Inc.
Siegwerk Canada Inc.
Sika Canada Inc.
Silver Standard Resources Inc.
Sleeman Breweries Ltd.
Société en Commandite Tafisa Canada Inc.
Sofina Foods Inc.
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Syncrude Canada Ltd.
TELUS Communications Inc.
TVI Pacific, Inc.
Tait Electronics Ltd.
Takeda Canada Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Tetley Canada Inc.
Teva Canada Limited
Thompson Creek Metals Company
TimberWest Forest Corp.
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Toys "R" Us (Canada) Ltd.
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Uranium One Inc.
Vale Inco Limited
Vallourec Tubes Canada Inc.
VAM Canada
Viterra Inc.
Votorantim Cement North America
VPL Enterprises Ltd.
VWR International
W.E.T. Automotive Systems Ltd.
Wal-Mart Canada Corp.
WD-40 Products Canada Ltd.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Yara Belle Plaine Inc.
Yukon Zinc Corporation
Zellstoff Celgar Partnership Limited

Attachment B – 2011 Commercial Industrial Market (n=268)

3M Canada Company
A&W Food Services of Canada Inc.
ABB Inc.
Abbott Laboratories, Limited
ACA Co-operative Limited
Agfa Healthcare Canada
Agfa Inc.
Air New Zealand
Air Products Canada Ltd.
Aker Chemetics
Akzo Nobel Canada Inc.
Alamos Gold Inc.
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Allergan Canada Inc.
Aluminerie Alouette Inc.
Amcor Limited
Amgen Canada Inc.
Amway Canada Corporation
Andrew Peller Limited
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal Tubular Products - Automotive Division
Arrow Transportation Systems Inc.
Ashland Inc.
Ashland Inc. - Global Chemicals
Ashland Inc. - Performance Materials
Ashland Inc. - Valvoline
Ashland Inc. - Water Technologies
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
ATCO I-Tek
Atlantic Packaging Products Ltd.
Atotech Canada Ltd.
Autopro Automation Consultants Ltd.
AV Nackawic Inc.
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barkerville Gold Mines Ltd.
Barrick Gold Corporation
Basell Canada Inc.
BASF Canada Inc.
Baxter Corporation
Bayer Inc.
BHP Billiton - Ekati Diamond Mines
BHP Billiton Canada Inc.
Black Cat Blades Ltd.
Blue Mountain Resorts Limited
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Britco Structures Inc.
Broan-NuTone Canada Inc.
Bruce Power
Bunge North America
Cabot Canada Ltd.
Campbell Company of Canada
Canada Safeway Limited
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
Canon Canada Inc.
Canpotex Limited
Cargill Limited
Catalyst Paper Corporation
Caterpillar of Canada Corporation
Centerra Gold Inc.
CHEP Canada
Christie Digital Systems Inc.
CKF Inc.
CNH America, LLC.
Cognis Canada Corporation
Compass Group Canada
Co-op Atlantic
Country Ribbon Inc.
Cytec Canada Inc.
Daishowa-Marubeni International Ltd.
Danone Canada Inc.
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
DENSO Manufacturing Canada, Inc.
Direct Energy Marketing Ltd.
Dow Chemical Canada Inc.
Dow Corning Canada Inc.
Dr Pepper Snapple Group
Dr. Oetker Ltd.
DSM Nutritional Products Canada Inc.
Dundee Precious Metals
Dyno Nobel Canada Inc.
E.I. du Pont Canada Company
EFW Radiology
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
EMD Serono Canada Inc.
ERCO Worldwide
Essar Steel Algoma Inc.
EWOS Canada Ltd.
Ferrero Canada Limited Commercial Division

Attachment B – 2011 Commercial Industrial Market (n=268) (cont'd)

Ferrero Canada Limited Industrial Division
Finning International Inc.
Fisher & Paykel Healthcare Inc.
Forbo Linoleum Inc.
Gates Canada Inc.
General Kinetics Engineering Corporation
Gerdau Ameristeel
GlaxoSmithKline Inc.
Graceway Pharmaceuticals
Graham & Brown
Grand & Toy
Griffith Laboratories Limited
Group SEB Canada Inc.
Henkel Canada Corporation
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Hudson's Bay Company
HumanWare
Hunter Dickinson Inc.
Huntsman Polyurethane
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
INVISTA (Canada) Company
ITW Construction Products
J. H. Ryder Machinery Limited
Janssen Inc.
John Deere Limited Canada
Jubilant Life Sciences Limited - Draximage
Jubilant Life Sciences Limited - Draxis Pharma
Katz Group Canada Ltd.
Kellogg Canada Inc.
Kennametal Ltd.
Kimberly-Clark Corporation
Kinross Gold Corporation
Kruger Products
Kuehne + Nagel Ltd.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
LANXESS Inc.
Lego Systems, Inc.
Lehigh Hanson
Linde Canada Limited
L'Oréal Canada Inc.
Lotus Bakeries
Lowe's Companies, Inc.
LS Travel Retail North America
Mainstream Canada Ltd.
Mark Anthony Group
McCormick Canada Co.
McElhanney Consulting Services Ltd.
McElhanney Land Surveys Ltd.
MDA
MDS Nordion
Meridian Lightweight Technologies Inc.
Methanex Corporation
Michelin North America (Canada) Inc.
Minas Basin Pulp & Power Co. Ltd.
Mitsubishi Canada Limited
Montship Inc.
Morneau Sobeco Income Fund
Mustang Survival Corp.
Mylan Pharmaceuticals ULC
Navtech Systems Support Inc.
Neopost Canada
Newmont Mining Corporation of Canada Limited
North Atlantic Refining
Northern Pulp Nova Scotia Corp.
NOVA Chemicals Corporation
Nova Scotia Power Inc.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Nycomed Canada Inc.
Oakrun Farm Bakery Ltd.
Omicron
P & H MinePro Services
Pan American Silver Corporation
Penske Truck Leasing
PepsiCo Canada
Phantom Mfg. (Int'l) Ltd.
Pharmascience Inc.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Potash Corporation of Saskatchewan Inc.
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Praxair Canada Inc.
Procter & Gamble Inc.
Puratos Canada Inc.
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto - Fer et Titane Inc.
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rogers Communications Inc.
Rothmans, Benson & Hedges Inc.
Russel Metals Inc.
SABIC Innovative Plastics Canada Incorporated
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis

Attachment B – 2011 Commercial Industrial Market (n=268) (cont'd)

Schneider Electric
Sears Canada Inc.
SEMAFO inc.
Sherritt International Corporation
Shire BioChem inc.
Shiseido (Canada) Inc.
Shoppers Drug Mart Corporation
Shore Gold Inc.
Siegwerk Canada Inc.
Siemens Canada Limited
Silver Standard Resources Inc.
Sleeman Breweries Ltd.
SMS Equipment Inc.
Société en Commandite Tafisa Canada Inc.
Sofina Foods Inc.
Sonoco Canada Corporation
Sultran Ltd.
Tait Electronics Ltd.
Takeda Pharmaceuticals North America, Inc.
Taro Pharmaceuticals Inc.
Tech Data Canada Corporation
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
TELUS Communications Inc.
Tembec Inc.
Thales Rail Signalling Solutions
The Bay
The Beer Store
The Churchill Corporation
The Home Depot Canada
The McElhanney Group Ltd.
The Mosaic Company
The Shaw Group Limited
Thompson Creek Metals Company
Thrifty Foods Inc.
TimberWest Forest Corp.
Timminco Limited
Tolko Industries Ltd.
Toromont CAT, A Division of Toromont Industries Ltd.
Trane Canada Co.
TVI Pacific, Inc.
Twin Rivers Paper Company
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Uranium One Inc.
Vale Inco Limited
Vicwest Income Fund
Viterra Inc.
Votorantim Cement North America
VPL Enterprises Ltd.
Wal-Mart Canada Corp.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Yara Belle Plaine Inc.
Zellers
Zellstoff Celgar Partnership Limited

Attachment C – 2010 Commercial Industrial Market (n=295)

A&W Food Services of Canada Inc.
Abbott Laboratories, Limited
Abbott Products Inc.
ACA Co-operative Limited
Agfa Healthcare Canada
Agfa Inc.
Agnico-Eagle Mines Limited
Ainsworth Engineered Canada L. P.
Air New Zealand
Air Products Canada Ltd.
Aker Chemetics
Alberta-Pacific Forest Industries Inc.
Alcon Canada Inc.
Allergan Canada Inc.
ALS Laboratory Group
AltaSteel Ltd.
Aluminerie Alouette Inc.
Amcor Limited
Amgen Canada Inc.
Amway Canada Corporation
Andrew Peller Limited
Anglo American Exploration (Canada) Ltd.
Apotex Inc.
ArcelorMittal Canada
ArcelorMittal Canada Contrecoeur-Ouest Inc.
ArcelorMittal Canada Hamilton
ArcelorMittal Canada Lachine
ArcelorMittal Canada Saint-Patrick
ArcelorMittal Dofasco Inc.
ArcelorMittal Mines Canada
ArcelorMittal P&T
ArcelorMittal Tubular Products - Automotive Division
Arkema Canada Inc.
Arrow Transportation Systems Inc.
Ashland Distribution
Ashland Global Chemicals
Ashland Performance Materials
Ashland Water Technologies
Astellas Pharma Canada Inc.
AstraZeneca Canada Inc.
Atlantic Packaging Products Ltd.
Atotech Canada Ltd.
AV Nackawic Inc.
Axcan Pharma Inc.
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barrick Gold Corporation
BASF Canada Inc.
Baxter Corporation
Bayer Inc.
Beiersdorf Canada Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
BHP Billiton - Ekati Diamond Mines
BIC Graphic Canada
bioMérieux Canada Inc.
Biovail Corporation
Boehringer Ingelheim (Canada) Ltd.
Bombardier Transportation Canada Inc.
Brink's Canada Limited
Bristol-Myers Squibb Canada Co.
Bronswerk Group
Bruce Power
Cabot Canada Ltd.
Cadbury North America
Campbell Company of Canada
Canada Safeway Limited
Canadelle Inc.
Canadian Forest Products Ltd.
Canadian National Railway Company
Canadian Pacific Railway
Canexus Limited
Canfor Pulp Limited Partnership
Canpotex Limited
Cargill Limited
Caterpillar of Canada Corporation
Centerra Gold Inc.
CHEP Canada
Chubb Edwards
CKF Inc.
CNH America, LLC.
Coca-Cola Bottling Company
Cognis Canada Corporation
Compass Group Canada
Co-op Atlantic
Cooper B-Line
Cooper Bussmann
Cooper Crouse Hinds
Cooper Hand Tools
Cooper Industries (Canada) Inc.
Cooper Lighting
Cooper Power Systems
Cooper Power Tools
Cooper Wiring Devices
Corby Distilleries Limited
Country Ribbon Inc.
Covance (Canada) Inc.
Cytec Canada Inc.
Daishowa-Marubeni International Ltd.
Danfoss Inc.
Danone Canada Inc.
Davis + Henderson
De Beers Canada Inc., Corporate Division

Attachment C – 2010 Commercial Industrial Market (n=295) (cont'd)

De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
DENSO Manufacturing Canada, Inc.
Dow Chemical Canada Inc.
Dow Corning Canada Inc.
Dr Pepper Snapple Group
DSM Nutritional Products Canada Inc.
Dundee Precious Metals
E.I. du Pont Canada Company
Eaton Corporation
EFW Radiology
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Enbridge Gas Distribution Inc.
Essar Steel Algoma Inc.
Evonik Degussa Canada Inc.
EWOS Canada Ltd.
FANUC CNC AMERICA Corporation
Ferrero Canada Limited Commercial Division
Ferrero Canada Limited Industrial Division
Finning (Canada)
Finning International Inc.
Fisher & Paykel Healthcare Inc.
FMC of Canada, Ltd.
Fraser Papers Inc.
FundSERV Inc.
G4S Cash Services (Canada) Ltd.
Galderma Canada Inc.
Gates Canada Inc.
GDF SUEZ Energy North America, Inc.
General Kinetics Engineering Corporation
GlaxoSmithKline Inc.
Goldcorp Inc.
Graceway Pharmaceuticals
Grand & Toy
Griffith Laboratories Limited
Group SEB Canada Inc.
Gulf Chemical Canada
H. H. Angus & Associates Limited
H.J. Heinz Company of Canada Ltd.
HDS Retail North America
Hecla Mining Company
Henkel Canada Corporation
Hilti (Canada) Ltd.
Hobart Food Equipment Services Canada
Hoffmann-La Roche Ltd.
Hudson's Bay Company
HumanWare
Huntsman Polyurethane
IAMGOLD Corporation
INEOS Canada Partnership
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Interquisa Canada
INVISTA (Canada) Company
J. Ennis Fabrics Ltd.
J. H. Ryder Machinery Limited
John Deere Limited Canada
Johnson Matthey Ltd.
JTI-Macdonald Corp.
JYSK CANADA
Katz Group Canada Ltd.
Kellogg Canada Inc.
Kennametal Ltd.
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
LANXESS Inc.
Lehigh Hanson
Levi Strauss & Co. (Canada) Inc.
Lilydale Inc.
L'Oréal Canada Inc.
Mainstream Canada Ltd.
McCormick Canada Co.
McElhanney Consulting Services Ltd.
McElhanney Land Surveys Ltd.
MDA
MDS Nordion
Meridian Lightweight Technologies Inc.
Methanex Corporation
Michelin North America (Canada) Inc.
Mitsubishi Canada Limited
MMG Resources Inc.
Montship Inc.
Mother Parkers Tea & Coffee Inc.
Mustang Survival Corp.
Mylan Pharmaceuticals ULC
Neopost Canada
Nestlé Canada Inc.
New Horizon System Solutions LP
Newmont Mining Corporation of Canada Limited
Northern Pulp Nova Scotia Corp.
NOVA Chemicals Corporation
Nova Scotia Power Inc.
Novartis Pharmaceuticals Canada Inc.
Novo Nordisk Canada
Nycomed Canada Inc.
Oakrun Farm Bakery Ltd.
Octapharma Canada Inc.
Olin Chlor-Alkali Products

Attachment C – 2010 Commercial Industrial Market (n=295) (cont'd)

Osler, Hoskin & Harcourt, LLP
Pan American Silver Corporation
Patheon Inc.
Penske Truck Leasing
PepsiCo Canada
PERI Formwork Systems, Inc. Canada
Pfizer Canada Inc.
Phantom Mfg. (Int'l) Ltd.
Philips Electronics Ltd.
Pioneer Hi-Bred Limited
Poly-Drill Drilling Systems Ltd.
Potash Corporation of Saskatchewan Inc.
PPG Canada Inc.
PPG Canada Inc. - Fine Chemicals Division
PPG Canada Inc. - Industrial Coatings Division
PPG Canada Inc. - Performance Glazing Division
Praxair Canada Inc.
Puratos Canada Inc.
QIT-Fer et Titane Inc.
Randstad Canada
Reflex Instrument North America
Richemont Canada Inc.
Rio Tinto - Diavik Diamond Mines
Rio Tinto Iron Ore
Ritchie Bros. Auctioneers (Canada) Ltd.
Rogers Communications Inc.
Rothmans, Benson & Hedges Inc.
Royal Group, Inc.
Russel Metals Inc.
Saint-Gobain Abrasives Canada Inc.
Saint-Gobain Ceramic Materials Canada/Abrasive Materials
sanofi-aventis
Sapphire Technologies
Saskatchewan Roughrider Football Club
Schlumberger Oilfield Services
Schneider Electric
Sherritt Coal
Sherritt International Corporation
Shore Gold Inc.
Sico Inc.
Sidel Canada Inc.
Siemens Canada Limited
SMS Equipment Inc.
Sonoco Canada Corporation
Sultran Ltd.
Suncor Energy Inc.
Takeda Pharmaceuticals North America, Inc.
Taro Pharmaceuticals Inc.
Teck Resources Limited
Teck Resources Limited - Highland Valley Copper
Teck Resources Limited - Trail Operation
Teekay Corporation
Tembec Inc.
Teranet Inc.
Thales Rail Signalling Solutions
The Bay
The Beer Store
The Churchill Corporation
The McElhanney Group Ltd.
The Mosaic Company
The Shaw Group Limited
Thompson Creek Metals Company
Thrifty Foods Inc.
TimberWest Forest Corp.
Timminco Limited
Tolko Industries Ltd.
TomTom International
Toromont CAT, A Division of Toromont Industries Ltd.
Total E&P Canada
Ultramar Ltée
uniPHARM Wholesale Drugs Ltd.
Vale Inco Limited
Valeant Canada Limited
Valvoline
Vanguard Plastics Ltd.
Vicwest Income Fund
Viterra Inc.
Votorantim Cement North America
Wal-Mart Canada Corp.
Wescast Industries Inc.
West Fraser Timber Co. Ltd.
Winners Merchants International L.P.
Xstrata Copper Canada
Xstrata Nickel Canada
Xstrata Zinc Canada
Zellers
Zellstoff Celgar Partnership Limited

Attachment 219.8

Attachment D – FBC Comparators by Revenue

2012 Commercial Industrial Market companies: Annual revenues ½ to 2x the 2012 gross revenue of FBC ($293 million) (n=68)	
ATCO I-Tek	Morneau Shepell Inc.
Ainsworth Engineered Canada L. P.	North American Palladium Ltd.
Air Products Canada Ltd.	Northern Pulp Nova Scotia Corp.
Akzo Nobel Canada Inc.	Novo Nordisk Canada
Alamos Gold Inc.	OxyVinyls Canada Inc.
Alberta-Pacific Forest Industries Inc.	PPG Canada Inc.
Amgen Canada Inc.	PPG Canada Inc. - Fine Chemicals Division
BHP Billiton - Ekati Diamond Mines	PPG Canada Inc. - Industrial Coatings Division
Babcock & Wilcox Canada Ltd.	PPG Canada Inc. - Performance Glazing Division
Baxter Corporation	Penske Truck Leasing
Bayer Inc.	Philips Electronics Ltd.
Boehringer Ingelheim (Canada) Ltd.	Pioneer Hi-Bred Limited
Brink's Canada Limited	Rio Tinto - Diavik Diamond Mines
CAE Inc.	Ritchie Bros. Auctioneers (Canada) Ltd.
CHEP Canada Inc.	Rolls-Royce Canada Ltd.
CKF Inc.	SABIC Innovative Plastics Canada Incorporated
Canexus Limited	SEMAFO inc.
Christie Digital Systems Inc.	Saint-Gobain Abrasives Canada Inc.
Co-op Atlantic	Saint-Gobain Ceramic Materials Canada/Abrasive Materials
Coty Canada	sanofi-aventis
De Beers Canada Inc., Corporate Division	Schneider Electric
Deeley Harley-Davidson Canada	The Shaw Group Limited
ERCO Worldwide	Sleeman Breweries Ltd.
Eli Lilly Canada Inc.	Sonoco Canada Corporation
G4S Cash Services (Canada) Ltd.	Teranet Inc.
Henkel Canada Corporation	Teva Canada Limited
Henry Schein Canada	TimberWest Forest Corp.
Hilti (Canada) Ltd.	uniPHARM Wholesale Drugs Ltd.
INEOS Canada Partnership	Uranium One Inc.
KGHM International Ltd.	VWR International
Kimberly-Clark Corporation	Wescast Industries Inc.
LifeLabs	Yara Belle Plaine Inc.
Maidstone Bakeries Co.	Yukon Zinc Corporation
McCoy Corporation	Zellstoff Celgar Partnership Limited

Attachment 219.9

Attachment E – FBC/FEI Comparators by Revenue

2012 Commercial Industrial Market companies: Annual revenues ½ to 2x the 2012 gross revenue of FBC/FEI ($1,721 million) (n=56)	
AMEC Inc.	KPMG MSLP
Abbott Laboratories, Limited	Kellogg Canada Inc.
ArcelorMittal Canada	Kinross Gold Corporation
ArcelorMittal Canada Contrecoeur-Ouest Inc.	Kruger Products
ArcelorMittal Canada Hamilton	Lehigh Hanson
ArcelorMittal Canada Saint-Patrick	Linamar
ArcelorMittal Mines Canada	Lundin Mining Corporation
AstraZeneca Canada Inc.	Methanex Corporation
BASF Canada Inc.	Michelin North America (Canada) Inc.
BHP Billiton Canada Inc.	The Mosaic Company
The Bay	PepsiCo Canada
Bombardier Transportation Canada Inc.	Praxair Canada Inc.
Bruce Power L.P.	Procter & Gamble Inc.
CNH America, LLC.	Rio Tinto Iron Ore
Canadian Forest Products Ltd.	Russel Metals Inc.
Canfor Pulp Limited Partnership	SNC-Lavalin Group Inc.
Canon Canada Inc.	Sherritt Coal
Canpotex Limited	Teekay Corporation
Catalyst Paper Corporation	Tembec Inc.
The Churchill Corporation	Tolko Industries Ltd.
Compass Group Canada	Toromont CAT, A Division of Toromont Industries Ltd.
Dow Chemical Canada Inc.	Toys "R" Us (Canada) Ltd.
E.I. du Pont Canada Company	Vale Inco Limited
Essar Steel Algoma Inc.	Votorantim Cement North America
Finning Canada	West Fraser Timber Co. Ltd.
GlaxoSmithKline Inc.	Winners Merchants International L.P.
HudBay Minerals Inc.	Xstrata Nickel Canada
John Deere Limited Canada	Xstrata Zinc Canada

Attachment 220.1

FILED CONFIDENTIALLY

Attachment 221.1

FORTISBC – ELECTRIC DIVISION

GOVERNANCE COMMITTEE MEETING

2013 SHORT TERM INCENTIVE PLAN TARGETS

The executive compensation plan places a significant portion of compensation at risk through the Short Term Incentive (STI) Plan. The STI Plan recognizes the impact of this group on business results. Performance targets guide the team to execute results in key areas that add the most value for the customer and Company success of the business.

The 2013 Corporate STI Plan targets are presented to the Governance Committee for review, approval and recommendation to the Board of Directors. The targets have been updated to incorporate 2012 year-end performance.

DESIGN OF THE 2013 SHORT TERM INCENTIVE PLAN

A summary of the Corporation's 2013 STI Plan:

1. A minimum threshold of $37.5 million in earnings must be reached before any bonuses will be paid. The threshold reflects 85% of forecasted BCUC approved regulated earnings.

2. The threshold (50%), target (100%) and maximum (150%) works as follows: if below target, the variance from target is pro-rated between threshold (50%) and target (100%); if above target; the variance is pro-rated between target (100%) and maximum (150%).

3. Executive short term incentives have both an individual and a corporate component.

4. Target payout levels and the design of corporate and individual weightings for the purpose of determining STI payouts are as follows:

	Weightings		
Position	**Individual**	**Corporate**	**Target Bonus Level (% of Salary)**
President and CEO	20%	80%	50%
Vice Presidents	50%	50%	30 - 40%

5. Exceeding targets will result in a higher payout level; the maximum of which is 150% of target. The Board of Directors may, at their discretion, increase the payout to a maximum of 200%.

CORPORATE COMPONENT

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%**

Regulated Earnings

FortisBC electric uses regulated earnings as the financial performance measure.

The target for 2013 is $44.1 million. This reflects the 2013 approved return on equity of 9.15% (8.75% benchmark plus 40 bps risk premium) on allowed equity by the regulator, established through the Generic Cost of Capital (GCOC) hearing. Both the risk premium and the equity thickness are subject to review in the GCOC Phase 2 process which is currently underway. The decision could further impact 2013 earnings. If so, the earnings target will be adjusted to reflect the outcome of that process.

Safety

Ensuring a safe workplace is a priority for FortisBC.

All Injury Frequency Rate

The 2013 measure is based on the All Injury Frequency Rate (AIFR) for reporting the Company's safety performance. The AIFR rate measures medical aid and lost time accidents per 200,000 hours worked (or approximately 100 employees).

The AIFR for 2013 is 1.64. This is based on a three-year rolling average. The threshold and top out is a 10% variance from target.

Outlined below is the five-year trend of the AIFR.

All Injury Frequency Rate
Actuals from 2008 – 2012

	2008	2009	2010	2011	2012
AIFR	2.87	1.41	1.72	1.48	1.72
# of incidents	13	6	8	7	8

Recordable Vehicle Incidents

The recommended measure for 2013 for vehicle safety is recordable vehicle incidents. That is any incident that occurs while working, with the exclusion of vehicles that are properly parked.

The recordable vehicle incident target for 2013 is 27. This is based on a three-year rolling average (rounded to nearest whole number). The threshold and top out is a 10% variance from the target.

Outlined below is the five-year trend of recordable vehicle incidents.

Recordable Vehicle Incidents
Actuals from 2008 – 2012

2008	2009	2010	2011	2012
27	22	27	32	22

Customer Satisfaction

The Customer satisfaction measure represents a composite of customer satisfaction ratings obtained through a survey conducted on a quarterly basis. The target is based on the anticipated challenges in 2013. The minimum and maximum thresholds are based on a minus and plus .2 respectively. Areas surveyed include the contact center, field services, meter reading, energy efficiency and overall satisfaction.

Outlined below is a five-year trend of the customer survey results

Customer Satisfaction
Actuals from 2008 – 2012

2008	2009	2010	2011	2012
8.6	8.6	8.8	8.7	8.4

As part of benchmarking the Company's service, the Company surveys 350 customers (300 residential and 50 commercial). The survey is conducted on a quarterly basis. The satisfaction index is a weighted average of customers' opinions regarding overall satisfaction with the Company, field services, accuracy of meter reading, contact centre services and satisfaction with energy conservation information provided by the Company. In addition to the above, the Company surveys customers' opinions on other key issues such as price and reliability of electricity, environmental performance, billing accuracy and general satisfaction.

Reliability (SAIDI) – Duration of Outages

This measure represents the reliability of the distribution power system in terms of duration of outages. The 2013 target is the prior three year rolling average which is reported to BCUC. Threshold and maximum targets represent a 5% variance from the Target. The SAIDI results are normalized by using the Institute of Electrical and Electronics Engineers' standard of identifying "Major Event Days" and excluding them from the calculation.

Outlined below is the five-year trend of reliability (SAIDI) results.

SAIDI
Actuals from 2008 – 2012

2008	2009	2010	2011	2012
2.42	2.28	2.84	1.86	1.95

The proposed reliability target is the prior three-year rolling average for SAIDI. This is consistent with prior years' proposal.

In 2013, FortisBC will be executing a PCB remediation program on certain station equipment. The program will require planned outages on the system which will negatively affect SAIDI.

For the purpose of this target, these outages will be normalized out of the SAIDI results.

Regulatory

This measure represents the Company's regulatory performance in 2013 and is subjective.

Fundamental to FortisBC's success and its ability to execute its business and strategic plans, FortisBC must be successful in achieving reasonable and appropriate regulatory decisions from the BCUC on revenue requirements and capital related applications while maintaining constructive relationships with stakeholders.

FortisBC Electric will have a challenging regulatory calendar in 2013. Many of the initiatives from 2012 will carry over into 2013; particularly, the GCOC proceeding, the Advance Metering Infrastructure and the Acquisition of the City of Kelowna (COK) Utility Assets CPCNs. Other 2013 applications are the renewal of the 3808 Power Supply Agreement with BC Hydro, Kootenay Facilities CPCN and the Transmission Stepped Rate Application. Finally, FortisBC Electric will be filing a Revenue Requirements Application in the second quarter that is expected to engage significant resources across the organization for the remainder of the year.

Individual Executive Targets

Individual executive performance targets will be presented at the February 2013 meeting.

Attachment 221.1.3

HayGroup®

FORTIS BC

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fax +1.416.868.6871

www.haygroup.com/ca

Dear Jody:

June 3, 2013

Ms. Jody Drope
Chief Human Resources Officer
FortisBC
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Re: Response to BCUC Directive - Executive Compensation Review

Hay Group Limited ("Hay Group") has been retained by FortisBC to conduct a competitive review of its executive compensation as part of the response to the BCUC Directive. To fulfill this mandate, we benchmarked the total compensation package of nine executive roles against the market.

Hay Group and Executive Compensation Review

Hay Group is a global management consulting firm with over 50 years of experience providing independent executive compensation advisory services to companies in a wide variety of industries and corporate structures in Canada. We have the most comprehensive pay database in the country, backed by the world's leading methodology in determining the complexity of roles.

Further details are set out in our report Executive Compensation Review, May 2013, which includes benchmarking information on all elements of FortisBC's executive compensation as well as a discussion of whether the SERP is incentive-based or handled as a benefit, and how the 13 percent for SERP compares to amounts offered by comparable companies.

Summary of Findings

Based on our review, we observe a gap from market median in target total direct compensation for all executives of FortisBC against the Hay Group Commercial Industrial database. Base salary and target total cash are generally positioned around market median, but a significant loss of competitiveness is evident at target total direct level, primarily due to weakness in LTI compensation.

To address this evident compensation gap, FortisBC has implemented a Performance Share Unit ("PSU") plan supplementing the current LTI plan with effect from 2013. From our review of market practices, the use of PSUs has become more prevalent among Canadian utilities and general industry as they seek to align executive compensation with long-term sustained corporate performance. Based on our benchmarking exercise and understanding of the PSU plan, it is our view that this plan will assist in closing the compensation policy gap to market median.

Jody, I trust the accompanying report is of assistance to you. I will be happy to answer any questions that may arise.

Sincerely,
Hay Group Limited

Christopher A. Chen, LLB
National Director, Executive Compensation

cc: Kennedy Lee, Hay Group Limited

Attachment 221.2.1

Executive Pension and Benefits Review

Summary of Results

A presentation to FortisBC Inc.

June 6, 2011

TOWERS WATSON

Introduction

- FortisBC has engaged Towers Watson to conduct a review of the competitiveness of the company's executive pension and benefit programs, including:
  - Supplemental executive retirement plans (SERPs)
  - Savings / stock purchase plans
  - Active and retiree health and dental plans
  - Long-term and short-term disability
  - Life insurance
  - Vacation, holidays and other paid time-off
- The results for FortisBC (FBC) and FortisBC Energy (FBCE) have been compared to those of a peer group of 22 companies (see Appendix I for the peer group)
  - The results for FBC and FBCE have been compared to the quartiles for the peer group
- The analysis has been undertaken using the methodology and assumptions described in Appendix II

Scope of Review

- This review examines the benefits provided to the senior executives at FBC and FBCE
- For benefits and paid time-off, we have based our review on the information contained in Towers Watson's Benefits Data Source (BDS)
  - This information has been supplemented by executive-specific information where available (e.g. the vacation schedule for FBC executives)
- For pension and savings programs, we have based our review on publically-available information disclosed in each company's proxy circular, or other related disclosure
  - The proxy disclosure information has been supplemented by additional information from the Towers Perrin 2008 SERP Survey and the BDS
- When evaluating the executive pension and savings programs, we have assumed that the predominant plan provided to the Named Executive Officers (NEOs) at each peer company would also apply to the broader group of senior executives included in this review

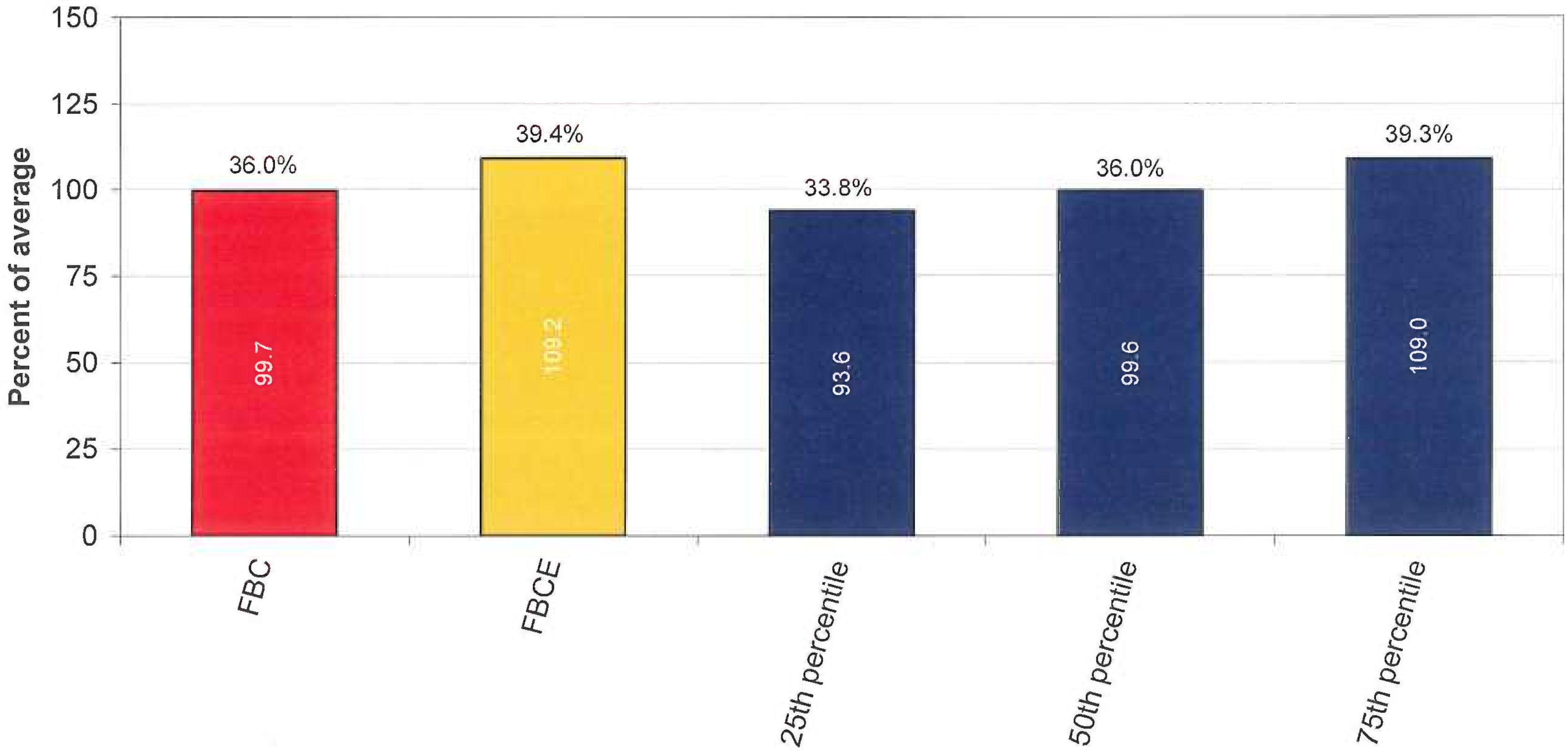
Executive Data

- This review has been conducted in respect of 11 executives at the Vice President and Executive Vice President levels
  - As directed by FortisBC, we have not considered special benefit arrangements that may have been negotiated by individual executives at any of the peer group companies
  - We have also excluded FortisBC's CEO from this analysis
- Our analysis has been conducted using the following three executive profiles:

Profile	Age	Service	Salary	Target Bonus
EVP	49	15	$ 295,000	40%
VP 1	55	13	$ 250,000	33%
VP 2	47	15	$ 235,000	33%

Employer-provided Value of All Benefits

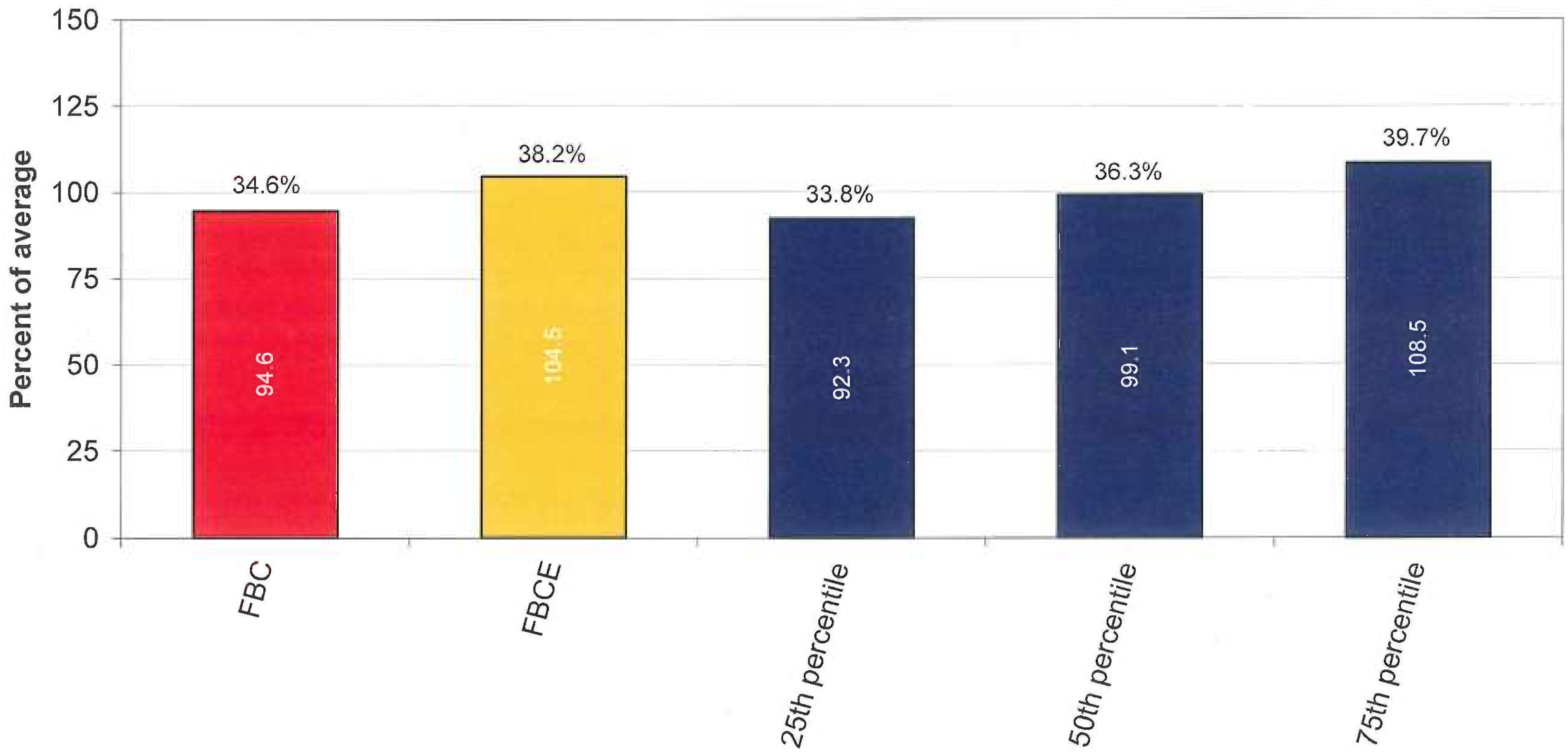
Profile: EVP



Average value: 36.1% of pay

Employer-provided Value of All Benefits

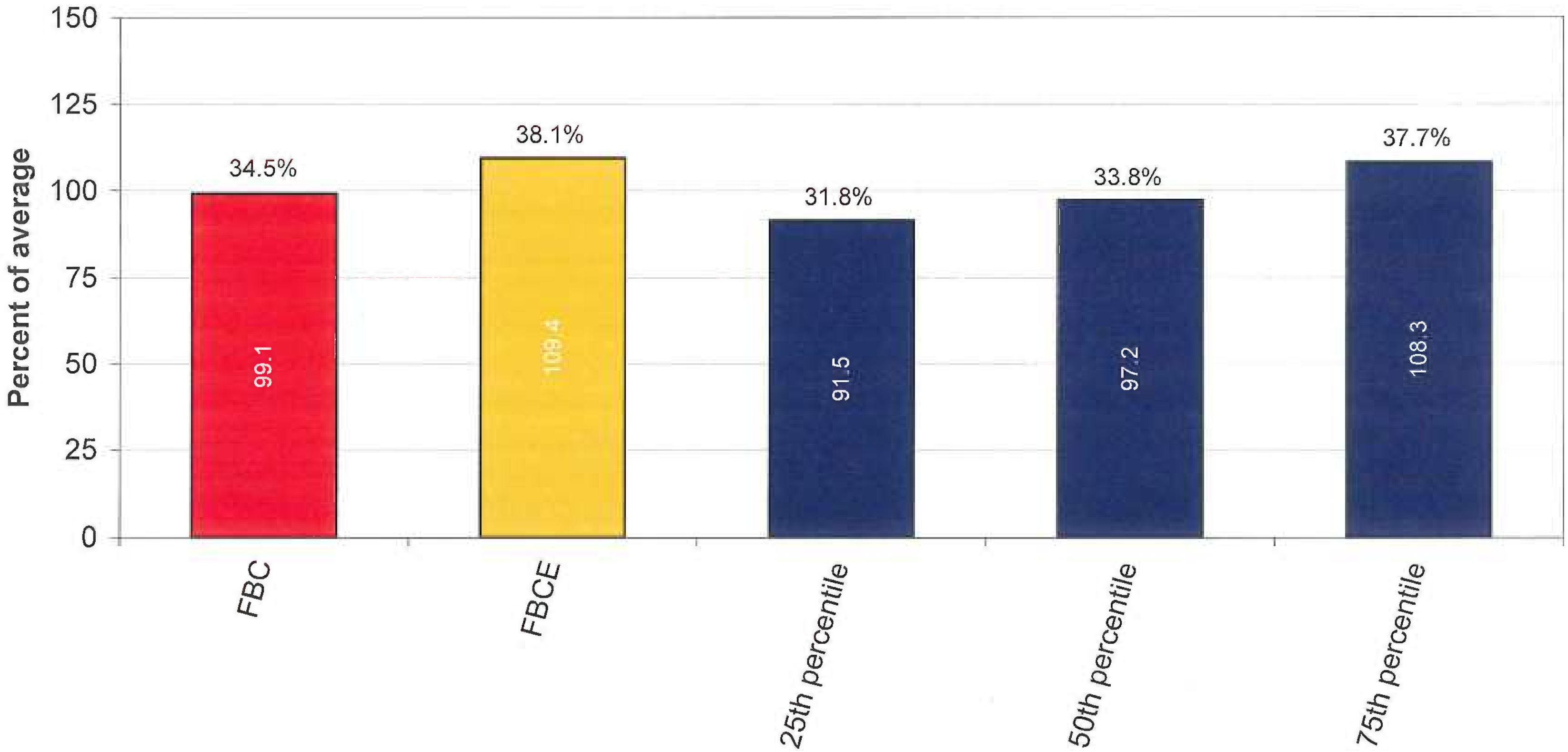
Profile: VP 1



Average value: 36.6% of pay

Employer-provided Value of All Benefits

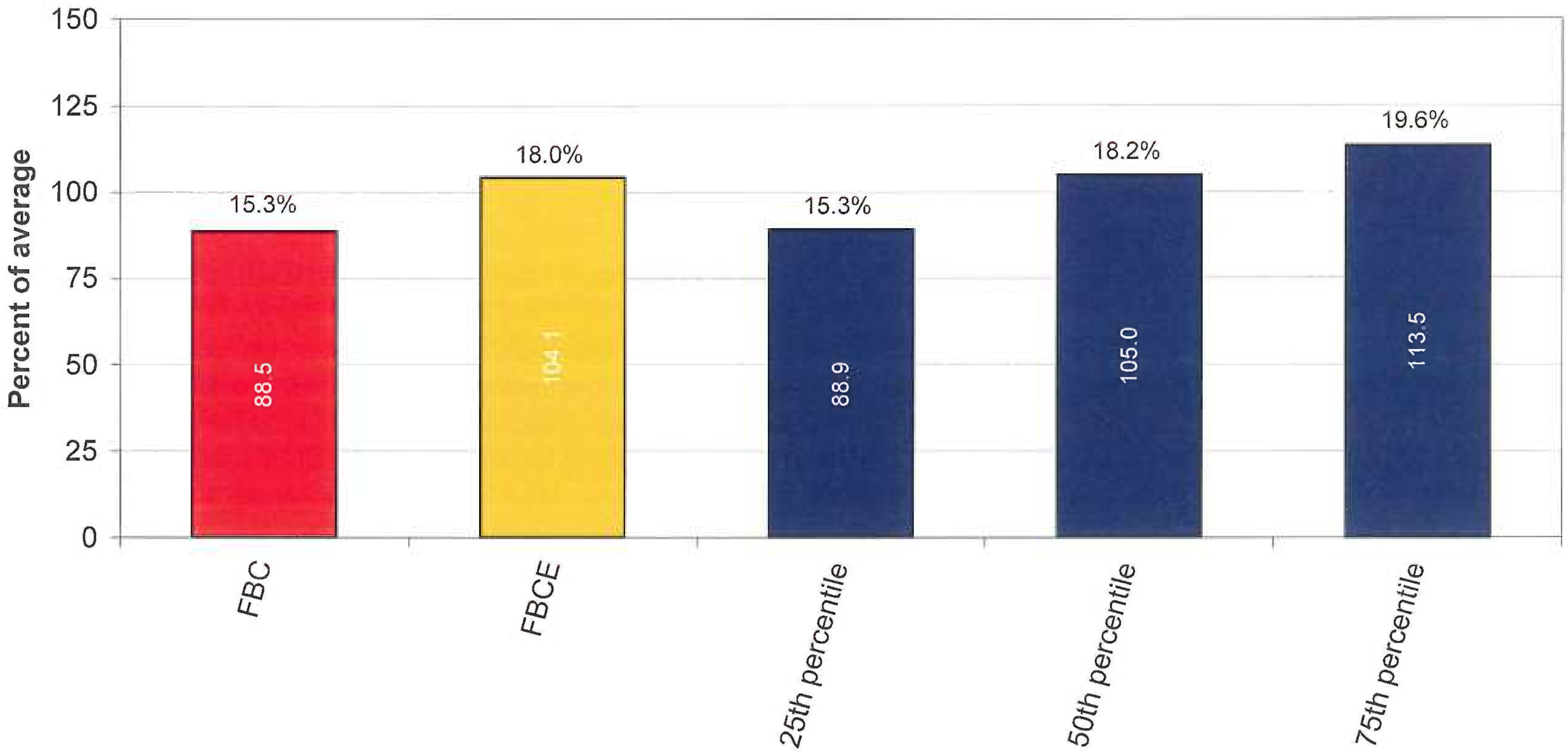
Profile: VP 2



Average value: 34.8% of pay

Employer-provided Value of Pension & Savings Programs

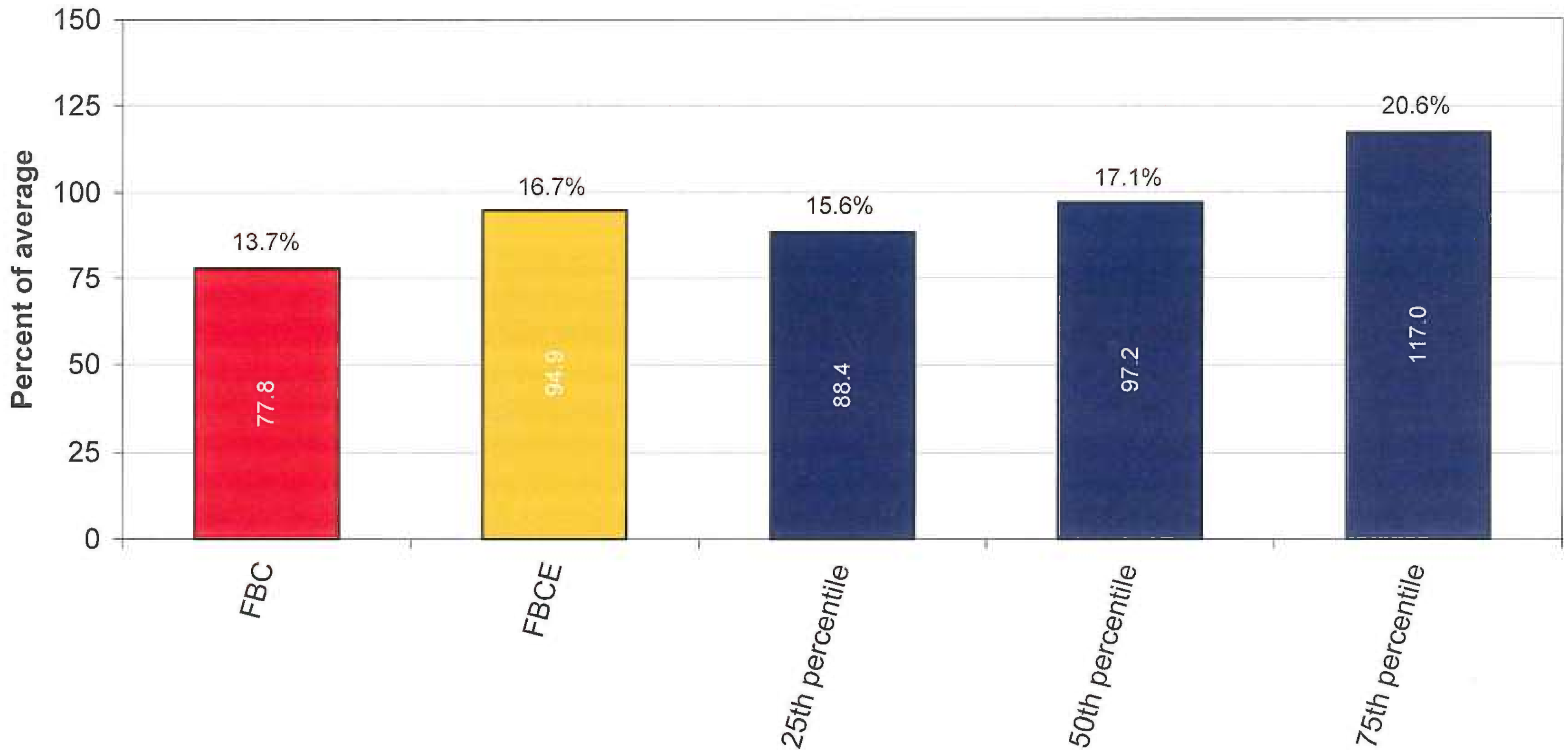
Profile: EVP



Average value: 17.3% of pay

Employer-provided Value of Pension & Savings Programs

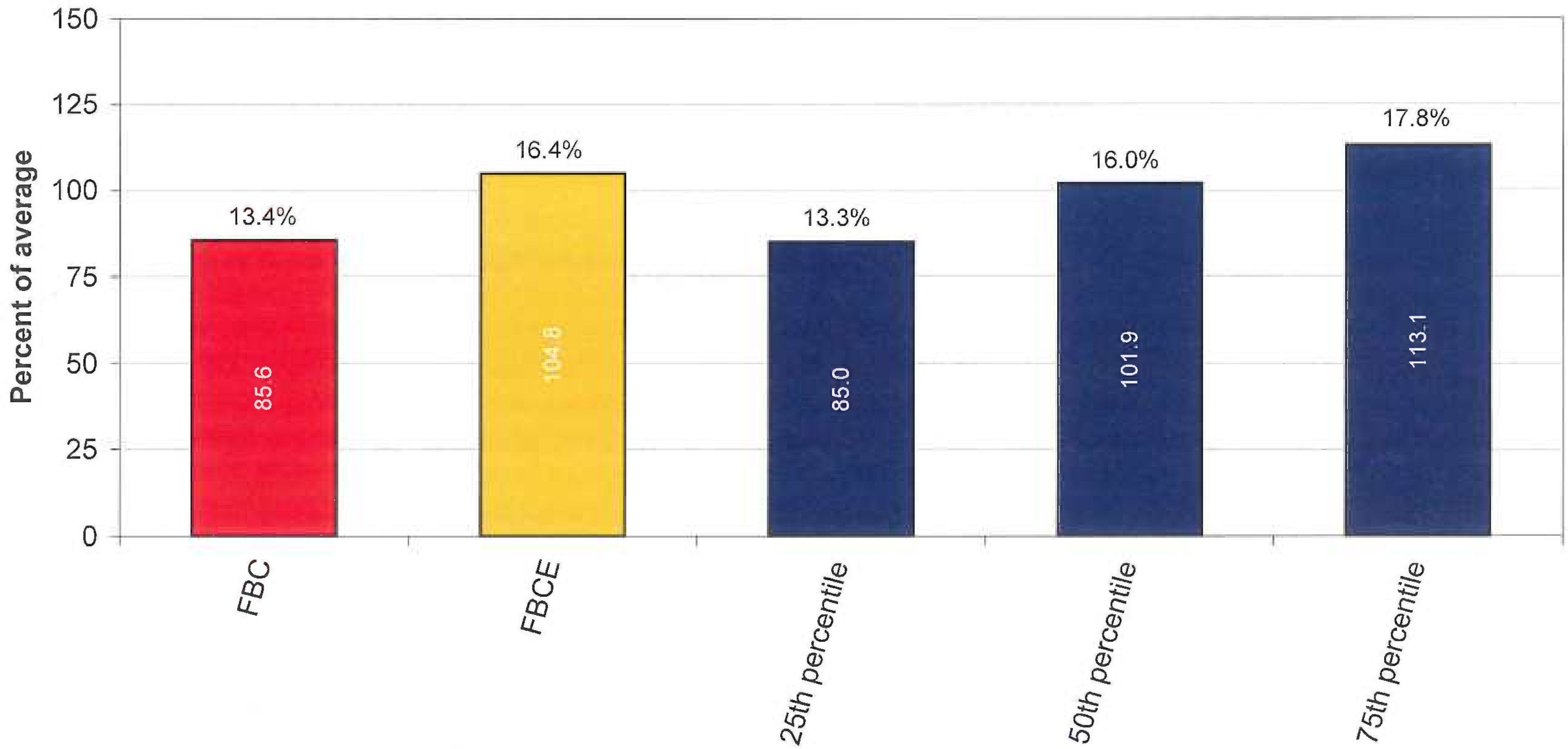
Profile: VP 1



Average value: 17.6% of pay

Employer-provided Value of Pension & Savings Programs

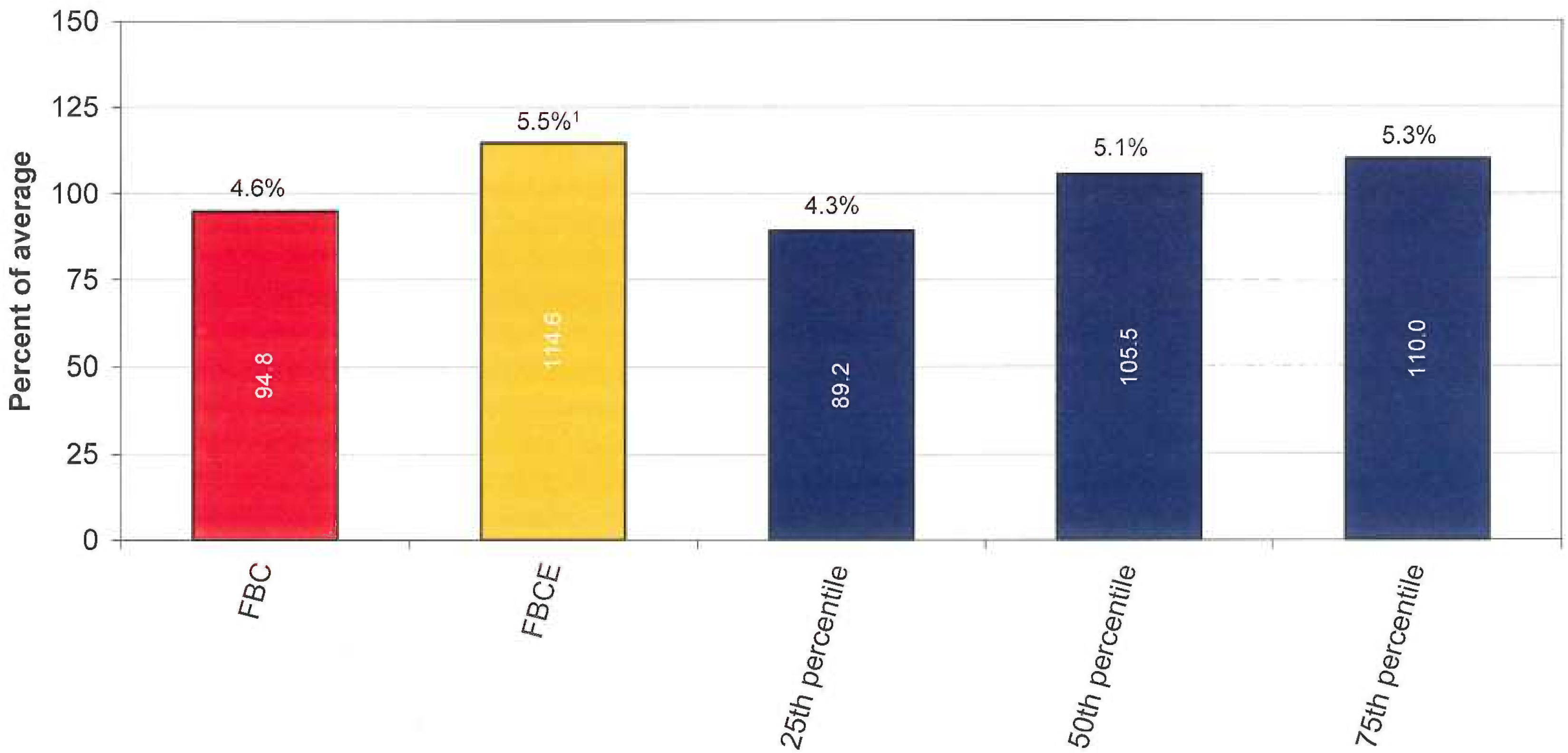
Profile: VP 2



Average value: 15.7% of pay

Employer-provided Value of Benefits Programs

Profile: EVP



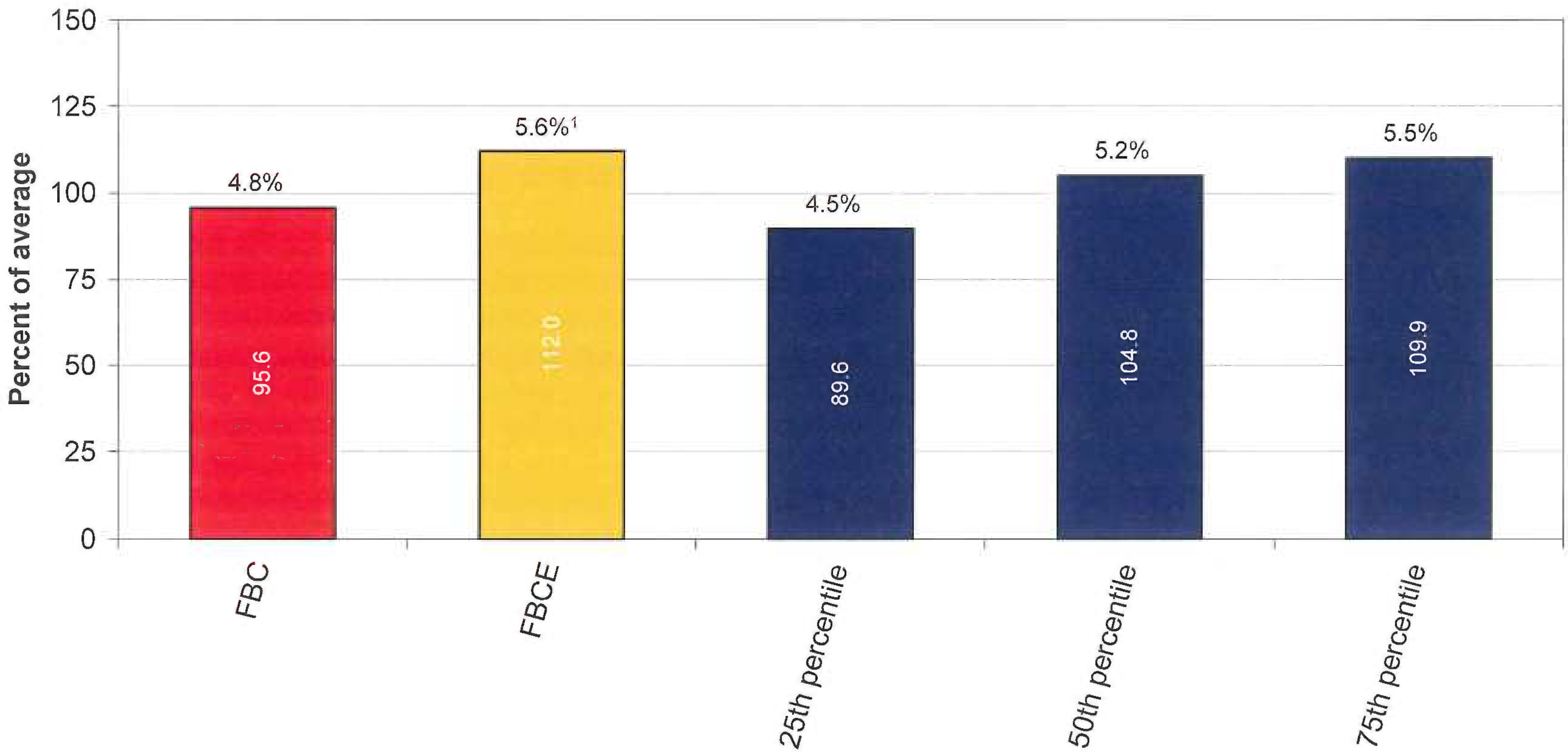
Average value: 4.8% of pay

Note:

1 Excludes value of 4% Power Credit, which has been reflected in the vacation program.

Employer-provided Value of Benefits Programs

Profile: VP 1



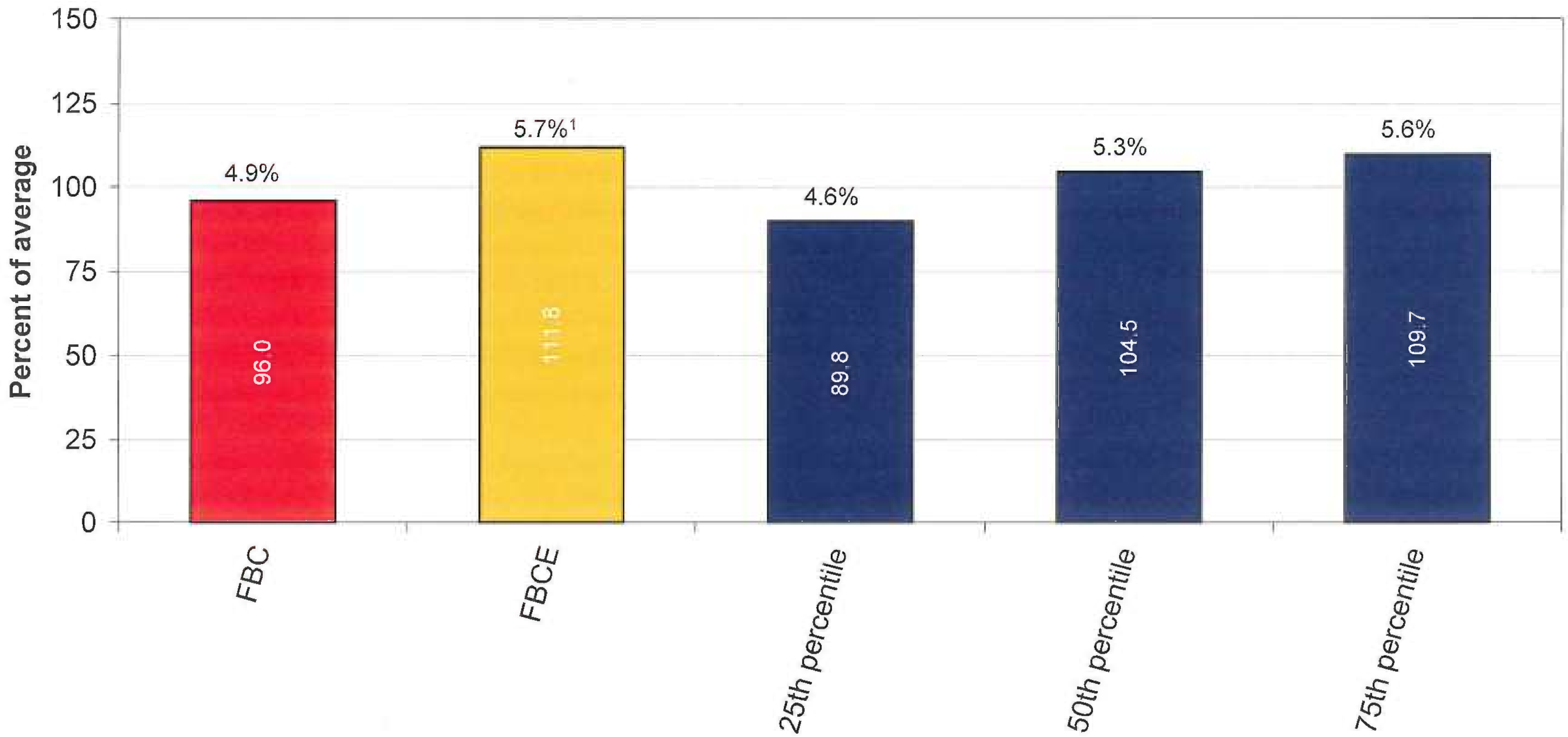
Average value: 5.0% of pay

Note:

1 Excludes value of 4% Power Credit, which has been reflected in the vacation program.

Employer-provided Value of Benefits Programs

Profile: VP 2



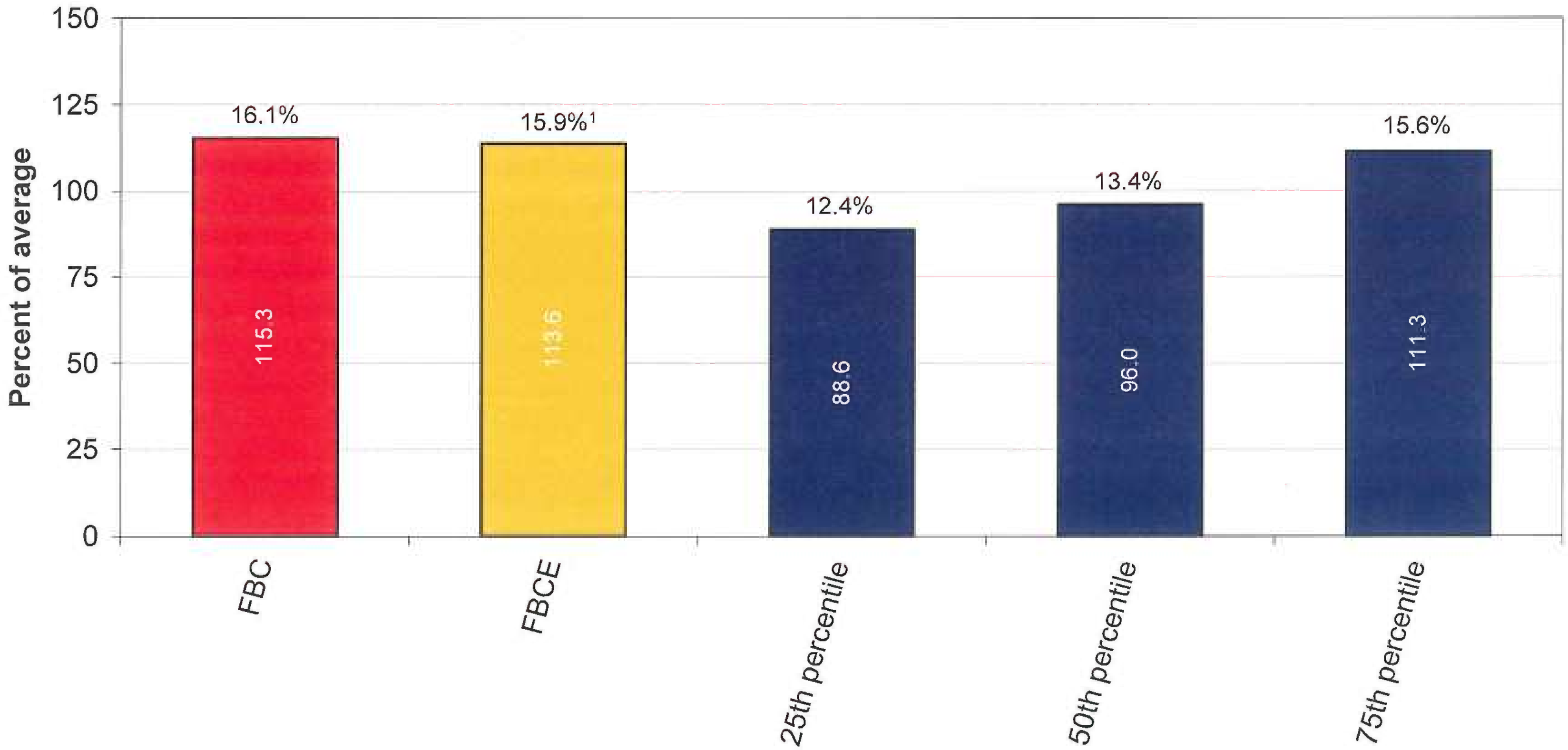
Average value: 5.1% of pay

Note:

1 Excludes value of 4% Power Credit, which has been reflected in the vacation program.

Employer-provided Value of Vacation, Holiday & Other Paid Time-off

Profile: EVP



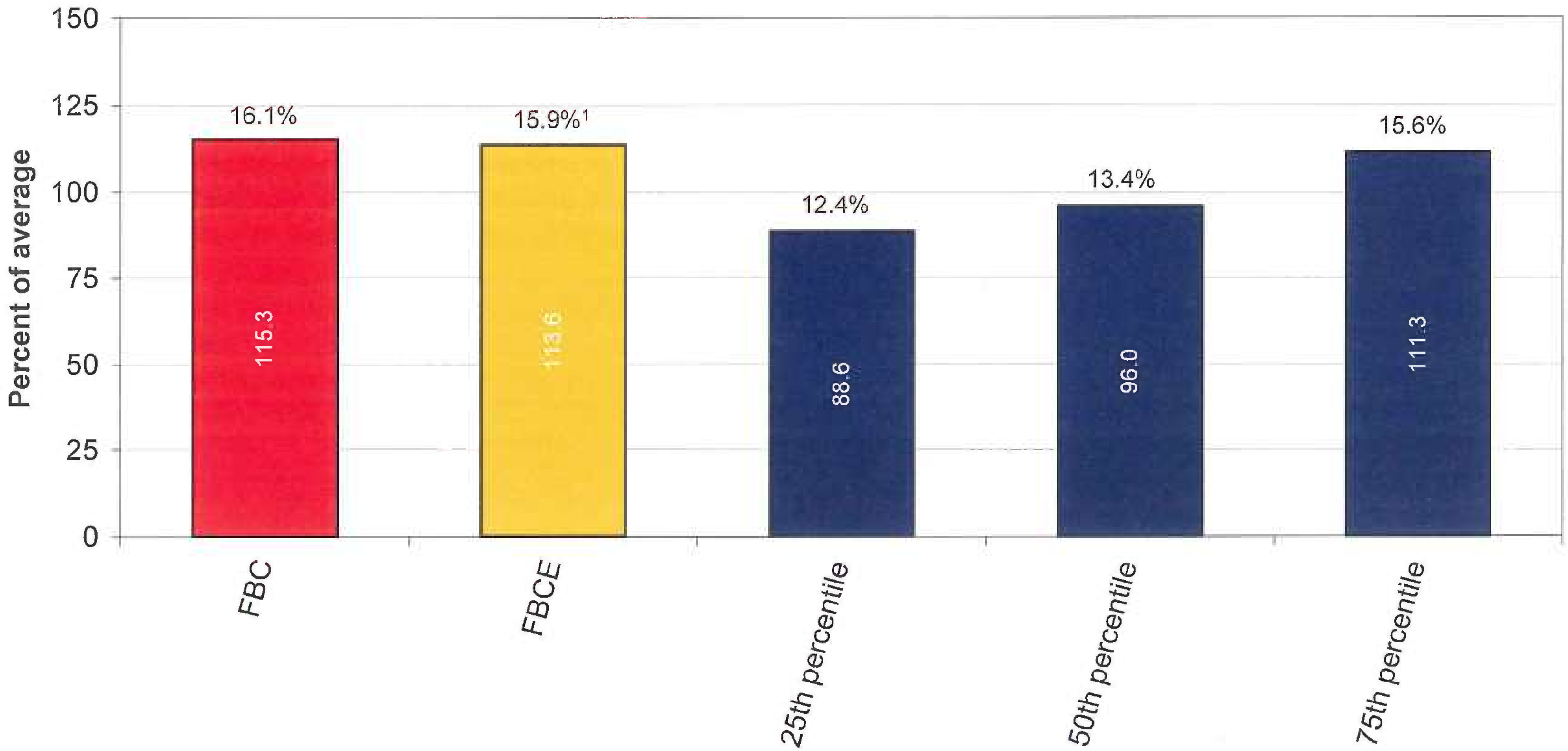
Average value: 14.0% of pay

Note:

[1] Includes value of 4% Power Credit

Employer-provided Value of Vacation, Holiday & Other Paid Time-off

Profile: VP 1



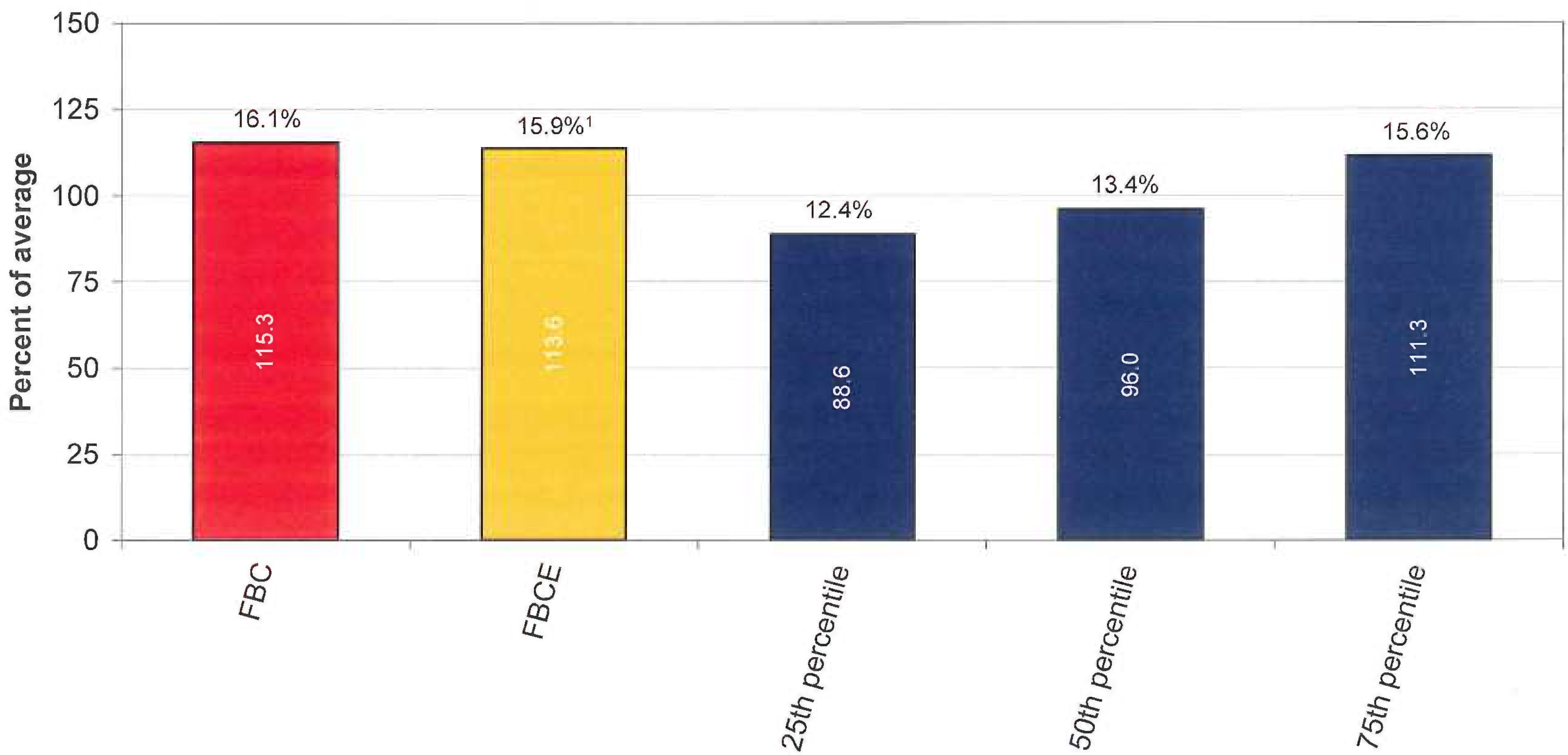
Average value: 14.0% of pay

Note:

1 Includes value of 4% Power Credit

Employer-provided Value of Vacation, Holiday & Other Paid Time-off

Profile: VP 2



Average value: 14.0% of pay

Note:

1 Includes value of 4% Power Credit

Executive Pension and Savings Programs

- The employer-provided value of the pension and savings programs provided to FBC executives is at approximately the 25th percentile of the peer group
- Due to the savings plan provided by FBCE, the employer-provided value of the pension and savings programs provided to FBCE executives is at approximately the median of the peer group
- The following pages provide additional commentary on the design features of the FBC, FBCE and peer group programs leading to these results

Executive Pension Programs

- The underlying value of a company's pension and savings programs is determined based primarily on the following design features:
  - **Existence of SERP** – Whether or not the company provides a supplemental pension arrangement in excess of the limits imposed by the Income Tax Act
  - **Type of SERP** – Whether the SERP is a defined benefit (DB) plan or a defined contribution (DC) plan
  - **Plan formula** (DB SERP) – The formula used to determine the total pension benefit under a DB SERP and the underlying registered pension plan
  - **Employer contribution rate** (DC SERP) – The rate of contributions (possibly notional) remitted by the plan sponsor in respect of each DC SERP member
  - **Inclusion of bonus in pensionable earnings** – The portion, if any, of short-term incentive payments that is included in the earnings used to calculate the pension benefit under a DB SERP, or the employer contributions under a DC SERP
  - **Indexation** (DB SERP) – The degree, if any, to which DB SERP benefits are indexed against the effect of inflation
  - **Employee contributions** – The level, if any, of employee contributions required under the plan

Executive Pension Programs

Existence of SERP

- FBC and FBCE:
  - Both companies provide a SERP to their executives
- Peer Group
  - All 22 companies in the peer group provide SERPs

Executive Pension Programs

Type of SERP

- FBC and FBCE:
  - Both companies provide a DC plan

- Peer Group
  - 14 companies provide a DB plan
  - 7 companies provide a DC plan
  - 1 company provides a DC registered plan with a DB SERP

Executive Pension Programs

Plan Formula (DB SERPs)

- FBC and FBCE:
  - N/A

- Peer Group – of the 15 companies providing DB SERPs:
  - 13 provide a benefit accrual of 2.0% of earnings per year of credited service
    - 7 do not apply any offset for CPP benefits
    - 6 do apply some level of offset for CPP benefits
  - 1 provides a benefit accrual in excess of 2.0% of earnings
    - 5% accrual per year of service for the first ten years, then no accrual for the next fifteen years
  - 1 provides a benefit accrual of less than 2.0% of earnings

Executive Pension Programs

Employer Contribution Rate (DC SERPs)

- FBC and FBCE:
  - Provide an employer contribution of 6.5% of earnings up to 50% of the annual maximum RRSP contribution, plus a contribution of 13% in excess of the maximum RRSP contribution
- Peer Group
  - The employer contribution rates for the 7 companies providing DC SERPs range between 5% and 13% of earnings

Executive Pension Programs

Inclusion of Bonus in Pensionable Earnings

- FBC and FBCE:
  - Both companies include bonus in pensionable earnings

- Peer Group
  - 19 companies include all or a portion of bonus in pensionable earnings
    - 17 include 100% of bonus
    - 2 include a portion of bonus in pensionable earnings
  - 3 companies do not include bonus in pensionable earnings

Executive Pension Programs

Indexation (DB SERPs)

- FBC and FBCE:
  - N/A

- Peer Group– of the 15 companies providing DB SERPs:
  - 10 provide some level of indexation against inflation
  - 5 do not provide any indexation

Executive Pension Programs

Employee Contributions

- FBC and FBCE:
  - Both companies require executives to contribute 6.5% of earnings, to a maximum of 50% of the annual maximum RRSP contribution
- Peer Group
  - 14 companies do not require executives to contribute to the pension plan
  - 8 companies require some level of contribution from the executives
    - Regardless of the underlying employee contribution rate, executive contributions to DB plans are virtually always limited to an amount that is tax deductible in accordance with the limits imposed by the Income Tax Act (approximately $16,500 in 2011)

Savings Programs

Existence of Savings Plan

- FBC:
  - Provides a 10% match on employee stock purchase to a maximum employer contribution of 1% of salary
- FBCE:
  - Provide a savings plan with employer contributions of 3% of salary, plus
  - Provides a 10% match on employee stock purchase to a maximum employer contribution of 1% of salary
- Peer Group
  - 13 of the 22 companies in the peer group offer savings plans
    - The average employer contribution is 3.6% of salary

Appendices

Peer Group

Appendix I

- ATCO Group
- BC Hydro
- Canadian Pacific Railway
- Capital Power Corporation
- Catalyst Paper
- Chevron
- ConocoPhillips
- Enbridge Gas Distribution
- ENMAX
- EPCOR
- Finning (Canada)
- FortisAlberta
- Insurance Corporation of BC
- Manitoba Hydro
- Methanex
- Nexen
- Spectra Energy
- Suncor
- Teck Resources
- TELUS
- TransAlta
- TransCanada PipeLines

Methodology

Valuation of Pensions and Benefits

- Pension and benefits data have been obtained using BENVAL® from Towers Watson's Canadian Benefits Data Source (BDS). The BDS contains detailed information on benefit programs offered by approximately 475 Canadian employers.
- BENVAL® is Towers Watson's methodology used to develop comparative values for the benefit plans provided by a group of companies. This methodology determines values using a standard set of actuarial methods and assumptions applied to a common employee population (for benefits) and three executive profiles (for pension, savings and paid time-off).
- To develop such values, benefits are initially analyzed in terms of when they become payable.
  - Those benefits payable in the future – defined benefit pension plans and post-retirement benefits – are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (Projected Unit Credit with service prorate method).
  - Those benefits potentially payable over the current year – defined contribution pension plans, pre-retirement death, disability benefits, and vacations and holidays – are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost method).
  - For health care and dental care coverage, the Term Cost method is based on the expected premium rate charged by an insurer for the coverage.
  - No other benefits are valued – parental leave and employee assistance programs for instance.
- The employer provided value is determined by deducting employee contributions from the total value.

Valuation of Pensions and Benefits (cont'd)

- An explanation of how each benefit plan is valued follows:

Defined Benefit Pension Plans

- The following elements are considered in determining comparative values for defined benefit pension plans: normal and early retirement benefits, disability benefits, pre- and post-retirement death benefits, termination benefits, and post-retirement pension adjustments.
- Post retirement pension adjustments are valued according to plan provisions or the actual company's policy when not stated in plan provisions.
- Plans are valued in accordance with the legislation where the plan is registered.

Valuation of Pensions and Benefits (cont'd)

Defined Contribution Pension Plans, Savings, Profit Sharing, and Stock Purchase Plans

- Plans are valued by determining employee and employer contributions made during the year of valuation.
- Employee contributions are adjusted to reflect savings opportunity depending on available income and level of employer match.
- Contribution levels to Profit Sharing plans are determined by taking the average of the actual past five years' contributions to the plan.

Life Insurance Plans

- Values for the following benefits are calculated: pre- and post-retirement group life insurance, accidental death and dismemberment benefits, and survivor income benefits.
- The amount of optional insurance elected is based on the level of company provided coverage and salary.

Disability Plans

- Short-term disability benefits include salary continuance and sickness plans.
- Values are determined according to specific plan provisions including waiting periods and benefit coordination.

Valuation of Pensions and Benefits (cont'd)

Health Care and Dental Care Plans

- Values are generated for pre- and post-retirement coverage. Post-retirement premiums are increased to reflect future inflation.
- Values are determined based on plan deductibles, coinsurance, and maximums as well as eligibility requirements.
- Vision care and hearing aid benefits are included in the Health Care plan value whether they are covered under the Health Care plan or a separate plan.
- Amounts allocated to the Health Care Spending Account are also included in the Health Care plan value.
- The provincial health care premiums are not included in the valuation.

Methodology

Valuation of Pensions and Benefits (cont'd)

Vacation and Holidays

- The value for vacation is determined based on the number of vacation days available. This includes bonus days when applicable. The number of days are determined in accordance with the company's schedule which is, usually, based on the employees' number of years of service.
- When the plan does not allow for the payment of unused vacation days during employment, we assume that employees with more than four weeks of vacation will forfeit some vacation days at the end of each year.
- The value for holidays is determined based on the number of holidays available. This includes all regular scheduled holidays and personal days.

Methodology

Valuation of Pensions and Benefits (cont'd)

Flexible Benefits

- The value determined for these benefits is based on the highest enrolled option for each plan.
- When not determined by the plan design, flexible benefit credits are allocated in the following order: health and dental care benefits, life insurance benefits, and disability benefits.

Valuation of Pensions and Benefits (cont'd)

Economic Factors	
Valuation interest rate	7.0% per year
Salary escalation	4.0% per year
Escalation of Year's Maximum Pensionable Earnings	3.0% per year
Inflation	2.5% per year
Increase in medical and dental premiums for post-retirement benefits valuation	4.0% per year

Valuation of Pensions and Benefits (cont'd)

Demographic Factors	
Mortality	• 1994 Uninsured Pensioner mortality without margins and 25 years of mortality improvement
Disability • STD • LTD • Other plans	 • Based on Commissioner's Disability Table, the Society of Actuaries TSA Group Table, and Towers Perrin's experience • Society of Actuaries 1981 Report on Mortality and Morbidity Experience, with adjustment • None
Termination of Employment	See table on next page
Retirement	See table on next page
Employee/family status	Employees are assumed to be married. Female spouses are assumed to be three years younger than male spouses. Employees are assumed to elect family coverage. Family is assumed to consist of two adults and two children.

Valuation of Pensions and Benefits (cont'd)

Termination of Employment

Age at Termination	Termination Rate
20 - 24	15% each year
25 - 30	10% each year
31 - 45	Starts at 9.5% at age 31 and reduced by 0.5% each age
46 - 54	2% each year
55 +	0% each year

Illustrative Probability of Retirement

Age at Retirement	Age of Unreduced Benefit			
	65	62	60	55
50	2%	2%	2%	2%
55	4%	4%	4%	15%
60	10%	10%	15%	15%
62	20%	30%	30%	50%

For example, under a plan that provides an unreduced benefit at age 62, 30% of active employees will retire at age 62.

Attachment 222.1

FILED CONFIDENTIALLY

Attachment 222.2

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September 27, 2010

Ms Jody Drope
Manager, Human Resources
Fortis BC Inc
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Dear Jody

As promised, this letter is to summarize the rationale for the selection of organizations in the market comparator group for Fortis BC and Terasen Gas. This recommendation is based on consultation with Fortis BC and Terasen Gas executives and HR representatives, as well as Hay Group's expertise and experience in external market comparison.

Fortis BC and Terasen Gas will have common long-term business goals and a common HR strategy going forward. They will also benefit from the ability to transfer talent from one organization to another. For these reasons, it is logical for Fortis BC and Terasen Gas to share a common compensation philosophy and to set salary ranges against a common comparator group. While this comparator group is likely to be similar to the comparator group used by Fortis Inc, the subsidiaries may compete for a different pool of talent than the parent and therefore may define the external market somewhat differently.

Comparator Group

The comparator group that we have recommended broadly represents Canadian industrial organizations that compete for a reasonably similar pool of talent. While individually each organization has its own specific pay policy and practice, together these organizations represent a stable, national comparator market for compensation. A complete list of these organizations is included as an appendix to this letter.

Selection Principles

This comparator group is a subset of the 539 organizations which have provided data to Hay Group's Canadian database. Since both Fortis BC and Terasen Gas recruit nationally for a variety of positions, a national comparator market is reasonable. Our approach was to start with this overall representation of the Canadian market and exclude various sectors whose talent pools are less relevant to Fortis BC. In our selection of organizations and industries, we were guided by the following general principles.

A stable comparator group

Generally speaking, larger comparator groups tend to be less susceptible to fluctuations caused by specific pay policies of any one organization. This is particularly important when the market data is being used to set base salary ranges. For specific pay decisions it can be better to analyze more specific geographic, or job related pay markets, but a broader comparator market for base salary ranges is more inclusive.

Exclusion by industry

Certain sub-sets of the Canadian marketplace compete for different pools of talent and have specific pay practices that are not relevant to either Fortis BC or Terasen Gas. We have excluded a number of industry groupings in order to develop a comparator group that was better aligned to the market where Fortis BC and Terasen Gas compete for talent. Industry groupings that were excluded include: financial services, pharmaceuticals, high technology, retail, and government.

Exclusion by geography

Upon review, it appeared that the Canadian database had a large number of Ontario-based industrial organizations that could potentially skew the data to represent more Eastern pay markets. While the national perspective is important for Fortis BC and Terasen Gas, both organizations are based in Western Canada therefore we were keen to avoid any inadvertent Eastern bias.

Industry orientation

Overall the comparator organizations include: all utilities in our database; natural resources companies including mining, forestry, and energy; engineering consulting; and industrial sector organizations based in Western Canada. The comparator group is primarily private sector, but includes relevant crown corporations and authorities such as provincial utilities and provincial safety authorities.

Utilities, natural resources companies, and organizations that recruit engineers will face similar recruiting and talent management challenges to Fortis BC and Terasen Gas. While revenues of resource-based organizations fluctuate with commodity prices, compensation policies are less volatile. Energy companies (and mining to a lesser extent) do have a reputation for high levels of compensation when responding to peaks in commodity prices. This is an important reality to recognize since Fortis BC and Terasen Gas will compete with these organizations for talent, particularly in the West. These pay practices are balanced out by forestry, industrial, manufacturing and broader public sector participants in the comparator group which help to provide an overall stable comparator market.

Jody, I hope that this letter helps to clarify the comparator group rationale for your future records. If you require any further information, please let me know.

Sincerely,

Tracy Bosch
Principal
Hay Group Limited

Attachment 222.5

FortisBC Inc.

Common Benefits Platform

June 13, 2011

This report has been provided solely for the use of FortisBC Inc. No one may use or reproduce the report or any data it contains for any other purpose. This report shall not be disclosed or provided in any manner whatsoever to any third party without the prior written permission of Towers Watson. This report and the know-how embodied in it are the confidential and proprietary work product of Towers Watson, which owns all related intellectual property rights.

TOWERS WATSON

Table of Contents

Overview of Common Benefits Platform Objectives

- In redesigning the pension and benefit programs, FortisBC established the following objectives:
  - Pension and savings programs should be excluded from the current review
  - A common platform of benefit programs for non-union employees should be established across FortisBC (FBC) and FortisBC Energy (FBCE)
  - The common platform should be positioned at the median relative to the FortisBC peer group, based on employer-provided values
    - Active and retiree benefits should be positioned near the median relative to the peer group
    - Paid-time off should be positioned at or below the median relative to the peer group

Active Benefit Program Design

Current Plans

- FBC and FBCE both offer flexible benefit programs for active employees
- The two flexible benefit programs are fundamentally similar, but with a variety of design differences:
  - FBCE provides Power Credits of 4% of pay to enable employees to buy back two weeks of vacation
  - FBCE also provides credits linked to certain options within the plan

Observations

- We observe the following:
  - FBCE's flex credits are linked to the price tags for the benefit Option 3
    - — This approach limits the company's ability to manage future increases in benefit costs as the flex credit allocation will increase automatically as the cost of benefits increase
  - Paid time-off levels are low, but this may be mitigated by employees' appreciation of flexibility of additional 'earned' days off
    - — FBC permits employees to earn 12 additional days off by working longer hours
    - — FBCE permits employees to earn 17 additional days off by working longer hours

Proposed Plan

- We have developed four proposed plans for discussion:

Proposal	Flexible Benefits	Pension & Savings Program	Vacation & Holidays	Power Credit
A	FBCE	FBCE[1]	FBCE	4%
B	FBCE	FBCE[1]	FBCE	0%
C	FBCE	FBCE[1]	FBC	4%
D	FBCE	FBCE[1]	FBC	0%

Note:

1. The value of FBCE's pension and savings programs is within 0.3% of those of FBC. Accordingly, while we have reflected those of FBCE, the results presented in this report would differ very little were FBC's pension and savings programs included instead of the FBCE programs.

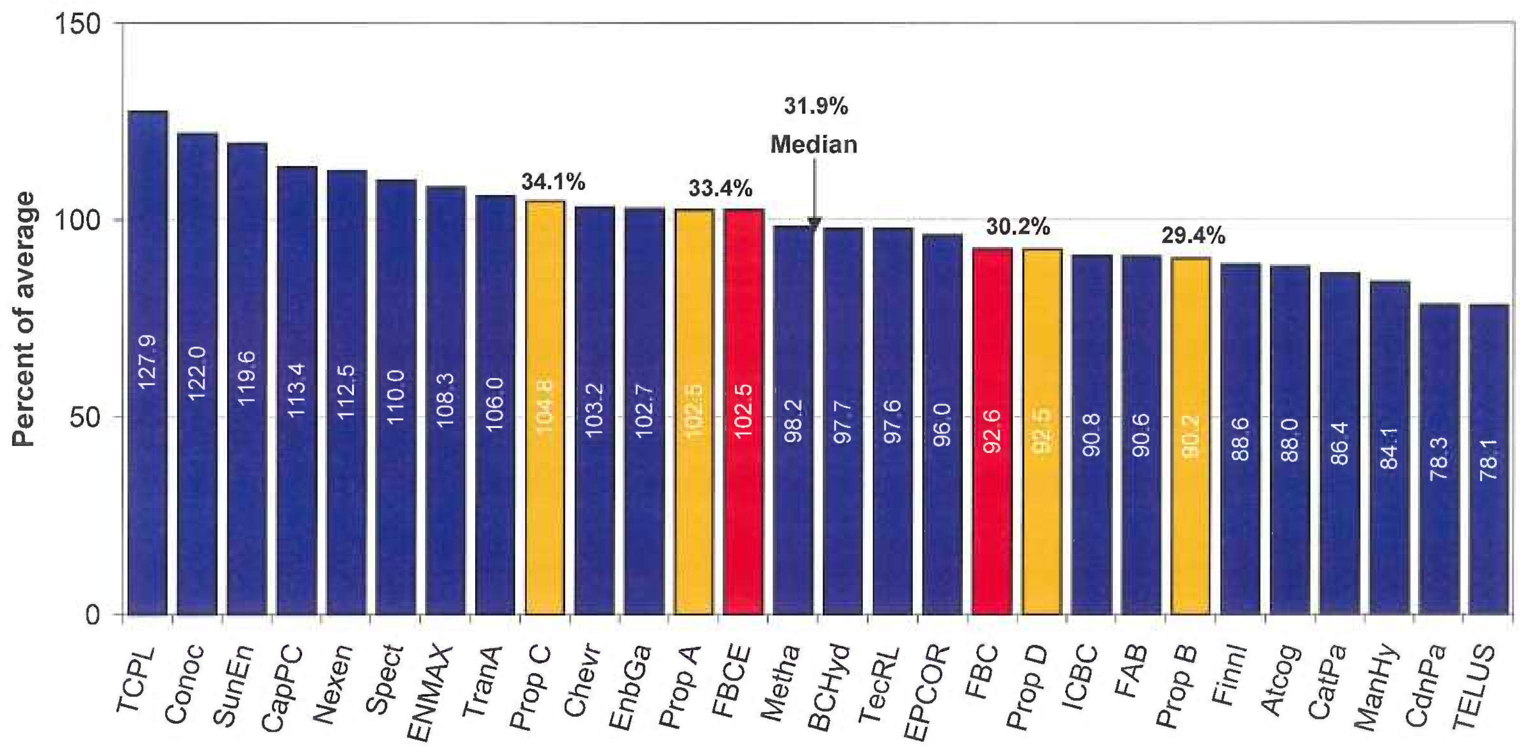
Benchmarking Analysis

Overview

- FortisBC has engaged Towers Watson to conduct a review of the competitiveness of the company's benefit programs
- The review includes the following benefit programs:
  - Disability programs (LTD, STD)
  - Life insurance
  - Extended health care and dental programs
  - Vacation, holidays and other paid time-off
- For reference, the pension and savings programs have also been included separately
- The results for FortisBC (FBC) and FortisBC Energy (FBCE) have been compared to those of a peer group of 22 companies (see Appendix I for peer group)
- The analysis has been undertaken using the methodology and assumptions described in Appendix II

All Pension, Benefit and Paid Time-off Programs

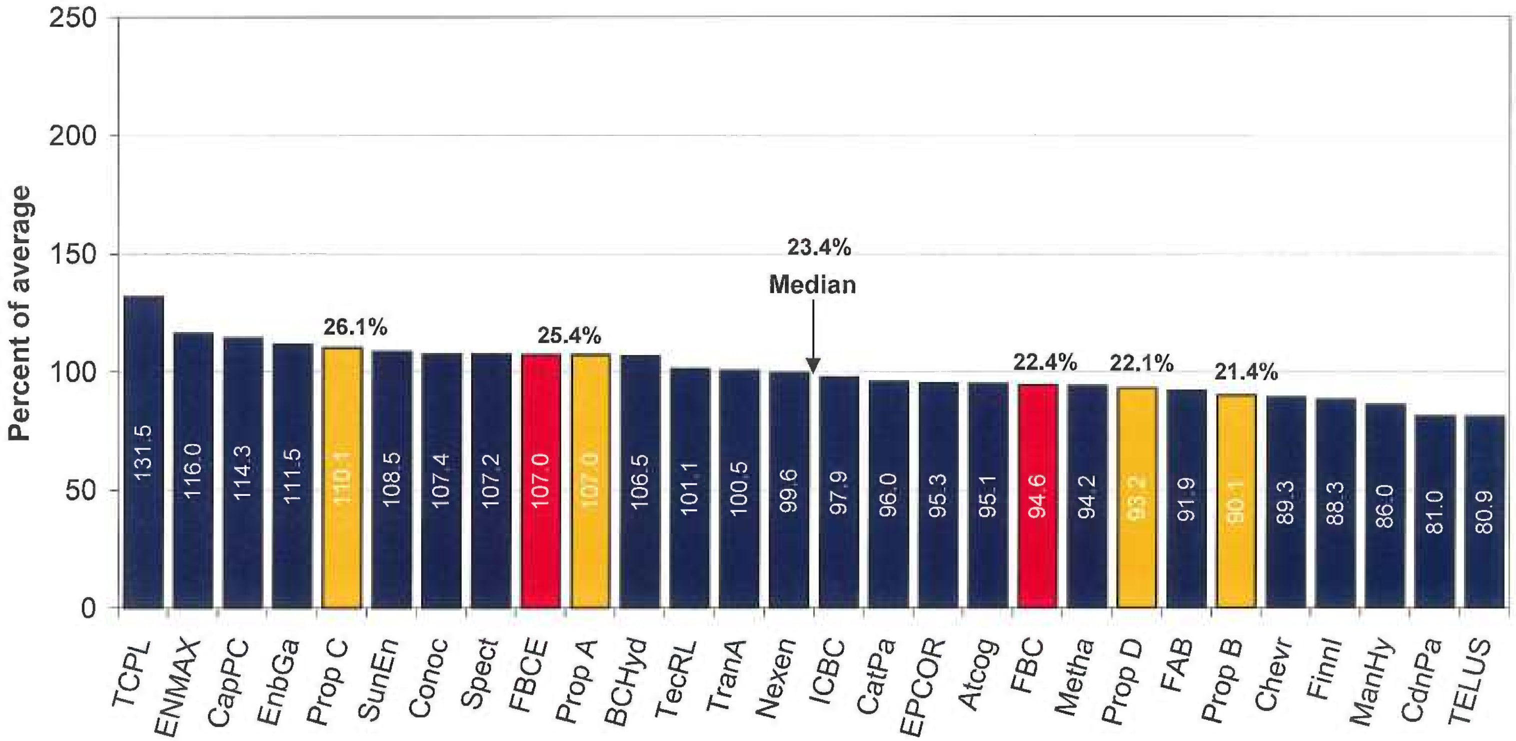
Employer-Provided Value – Excluding Employee Contributions



Average value: 32.6% of pay

Benefit & Paid Time-off Programs

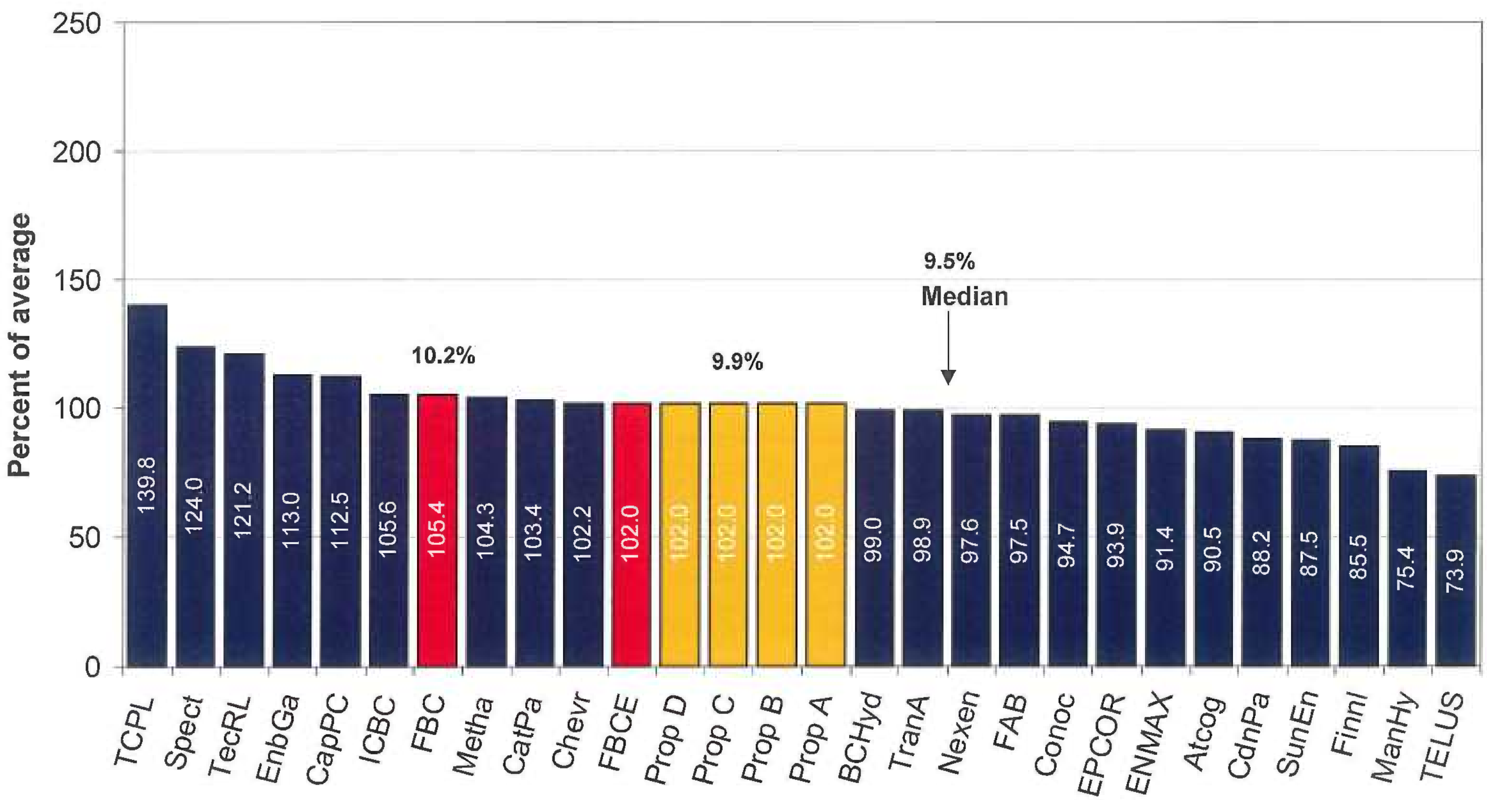
Employer-Provided Value – Excluding Employee Contributions



Average value: 23.7% of pay

Benefit Programs [1]

Employer-Provided Value – Excluding Employee Contributions



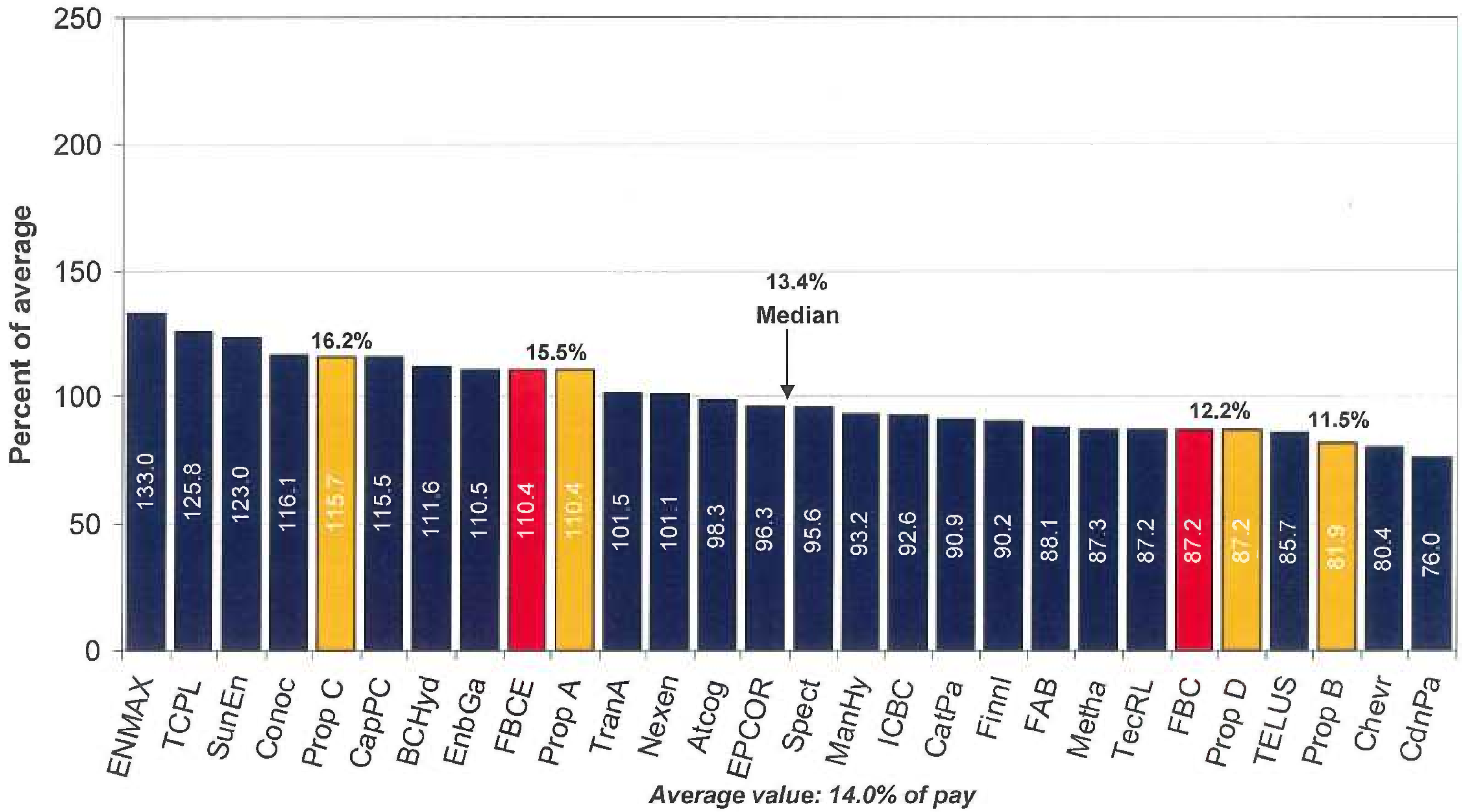
Average value: 9.7% of pay

Note:

1 The value of the 4% Power Credit has been included with the paid time-off programs and is therefore not reflected in the value of benefit programs shown on this page.

Paid Time Off [1]

Employer-Provided Value – Excluding Employee Contributions

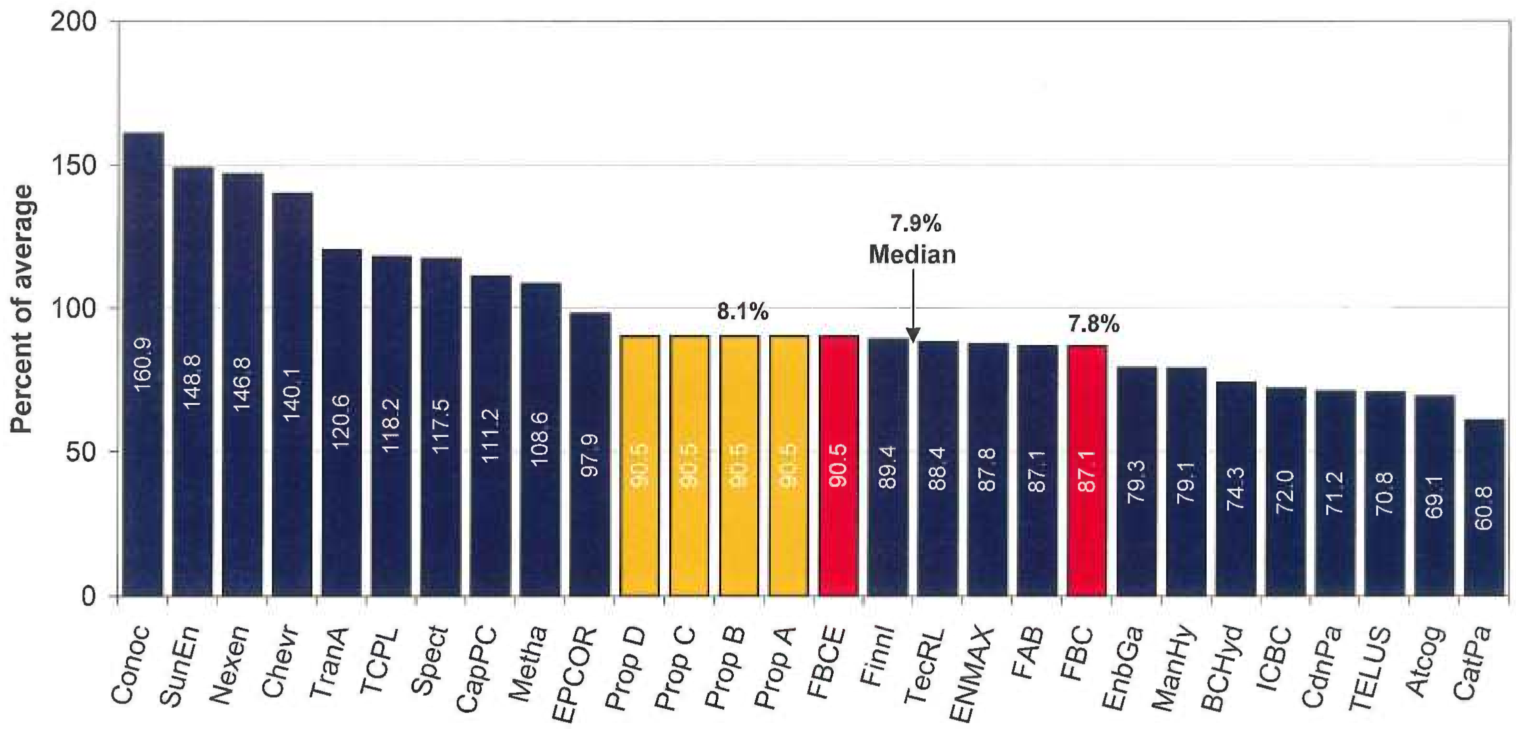


Note:

1 The value of the 4% Power Credit has been included with the paid time-off programs shown on this page.

Pension and Savings Programs

Employer-Provided Value – Excluding Employee Contributions



Average value: 8.9% of pay

Observations

Total Benefits & Paid Time-off Program

- The employer-provided value (excluding employee contributions) is generally used for purposes of competitive comparisons
  - The employer-provided value of the current benefits and paid time-off programs provided by FBCE are slightly above the median (approximately 107% of median)
  - The employer-provided value of the benefits and paid time-off programs provided by FBC are slightly below the median (approximately 94% of median)
  - The positioning of the employer-provided value of the proposed benefits and paid time-off programs depends on the 4% Power Credit:
    - If the 4% Power Credit is retained, the proposed program is above median (approximately 107% to 110% of median)
    - If the 4% Power Credit is eliminated, the proposed program is below median (approximately 90% to 93% of median)

Active Benefit Program Design

Flex Credit Formula

Current & Proposed

	FBC – Current	FBCE – Current	Proposed Plan
Summary	Full time employees receive: • 1.14% of pay, plus • $1,900 In addition, company will pay for provincial MSP premiums	Full time employees receive: • 1.43% of pay to pay for core LTD, basic and voluntary life insurance, plus • Flat amount of credits to pay for Option 3 for EHC and dental coverage and provincial MSP premiums, plus • Power Credits 4% of pay to buy back two weeks of vacation.	Full time employees receive: • TBD% of pay to pay for benefits, plus • Flat amount of credits to pay for provincial MSP premiums, plus • Power Credits of – Proposals A and C: 4% of pay to buy back two weeks of vacation, or – Proposals B and D: Nil.

Flex Credit Formula

Current & Proposed

	FBC – Current	FBCE - Current	Proposed Plan
	Detail – Full-time employee	Detail – Full-time employee	Detail – Full-time employee
Percent of pay	1.14% of pay to provide for LTD, basic and optional life insurance	1.43% of pay to provide for LTD, basic and voluntary life 4% of pay Power Credit	TBD% of pay, plus Power Credit of: ▪ Proposals A and C: 4% of pay ▪ Proposals B and D: Nil
Flat amount	$1,900 for EHC and dental	Based on family status	Based on family status
Flat amount by family status (rounded to nearest dollar)	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage,	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage, $300 if opt-out **EHC** $580 single / $930 couple / $1,350 family if elect coverage, $300 if opt-out **Dental** $600 single / $1,160 couple / $1,800 family if elect coverage, $300 if opt-out Company pays business travel accident (i.e., not a flex credit).	**MSP** $684 single / $1,244 couple / $1,368 family if elect coverage, $300 if opt-out **EHC** $580 single / $930 couple / $1,350 family if elect coverage, $300 if opt-out **Dental** $600 single / $1,160 couple / $1,800 family if elect coverage, $300 if opt-out Company pays business travel accident (i.e., not a flex credit).

Basic and Optional Life Insurance

Current & Proposed

Benefits	FBC – Current	FBCE - Current	Proposed Plan
Basic Life Insurance			
Benefit Schedule	1 x base earnings	1 x base earnings	1 x base earnings
Overall Maximum	$500,000	$900,000 (combined with Voluntary)	$900,000 (combined with Voluntary)
Employee Contribution	0%; company paid	0%; company paid	0%; company paid
Voluntary Life			
Benefit Schedule	N/A	1 X base earnings	1 X base earnings
Employee Contribution	N/A	0%; company paid May opt-out	0%; company paid

Basic and Optional Life Insurance

Current & Proposed

Benefits	FBC – Current	FBCE – Current	Proposed Plan
Employee Optional Life			
Benefit Schedule	Units of $25,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000
Employee Contribution	100%	100%	100%
Optional Dependant Life			
Spouse	Units of $25,000 to maximum of $250,000	Units of $50,000 to maximum of $750,000	Units of $50,000 to maximum of $750,000
Child	Units of $5,000 to maximum of $25,000	$10,000	$10,000
Employee Contribution	100%	100%	100%

Accidental Death and Dismemberment

Current & Proposed

Benefits	FBC – Current	FBCE – Current	Proposed
Employee Basic 24-Hour Accident			
Benefit Schedule	$50,000	None	None
Employee Contribution	0%; Company paid	N/A	N/A
Optional AD&D			
Employee Benefit	Units of $25,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000
Spouse Benefit	None	Units of $50,000 to maximum of $500,000	Units of $50,000 to maximum of $500,000
Child Benefit	None	$10,000	$10,000
Employee Contribution	100%	100%	100%
Business Travel Accident			
Employee Benefit	None	3 x base earnings to maximum of $1,000,000	3 x base earnings to maximum of $1,000,000
Employee Contribution	N/A	0%; company paid	0%

Short Term Disability

Current & Proposed

	FBC – Current	FBCE – Current	Proposed
Benefit Amount	Initial weeks at 100%, remainder of weeks at 70% based on service	Initial weeks at 100%, remainder of weeks at 70% based on service	Initial weeks at 100%, remainder of weeks at 70% based on service
Benefit Schedule	Years of Svc / # Weeks at 100%* All / 13 *Balance of 26 weeks at 70%	Years of Svc / # Weeks at 100%* <1 / 3 1 / 5 2 / 7 3 / 10 4 / 13 5 / 15 6 / 17 7 / 19 8 / 21 9 / 24 10+ / 26 *Balance of 26 weeks at 70%	Years of Svc / # Weeks at 100%* <1 / 3 1 / 5 2 / 7 3 / 10 4 / 13 5 / 15 6 / 17 7 / 19 8 / 21 9 / 24 10+ / 26 *Balance of 26 weeks at 70%
Benefit Period	26 weeks	26 weeks	26 weeks
Employee Contribution	0%; company paid	0%; company paid	0%; company paid

Long Term Disability

Current

Classes	FBC Option 1	FBC Option 2	FBCE Option 1	FBCE Option 2	FBCE Option 3	FBCE Option 4
Benefit Schedule	70%	55%	70%	60%	70%	60%
Overall Maximum	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month
Elimination Period	26 weeks	26 weeks	26 weeks	26 weeks	26 weeks	26 weeks
Cost of Living Adjustments	None	None	None	None	Indexed with CPI to 5% maximum	Indexed with CPI to 5% maximum
Definition of Disability	2 years own occupation; any occupation thereafter	2 years own occupation; any occupation thereafter	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job
Benefit Period	To age 65	To age 65	To age 65	To age 65	To age 65	To age 65
Tax Status of Benefit	Taxable	Non-taxable	Taxable	Non-taxable	Taxable	Non-taxable
Employee Contribution	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only

Long Term Disability

Proposed

Classes	Option 1	Option 2	Option 3	Option 4
Benefit Schedule	70%	60%	70%	60%
Overall Maximum	$15,000 / month	$15,000 / month	$15,000 / month	$15,000 / month
Elimination Period	26 weeks	26 weeks	26 weeks	26 weeks
Cost of Living Adjustments	None	None	Indexed with CPI to 5% maximum	Indexed with CPI to 5% maximum
Definition of Disability	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job	Unable to perform 60% of your job for first 24 months; thereafter unable to earn more than 75% of pre-disability earnings at any job
Benefit Period	To age 65	To age 65	To age 65	To age 65
Tax Status of Benefit	Taxable	Non-taxable	Taxable	Non-taxable
Employee Contribution	100%; flex credits only	100%; payroll deduction only	100%; flex credits only	100%; payroll deduction only

Provincial Health Care

Current & Proposed

	FBC Option 1	FBC Option 2	FBCE Option 1	FBCE Option 2	Proposed Option 1	Proposed Option 2
Benefit	No coverage	Coverage	No coverage	Coverage	No coverage	Coverage
Employee Contribution	N/A	0%; company paid	N/A	100%; employee-paid	N/A	100%; employee paid

Extended Health Care Benefit

Current

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Deductible	$0	$0	$100 per person	$0	$0
Hospital					
• Semi–Private	0%	100%	60%	80%	100%
• Convalescent Hospital	Not covered	$40 per person per day to maximum of 180 days	Not covered	Not covered	Not covered
Prescription Drugs					
• Coinsurance	85%	100%	60%	80%	100%
• Drugs Covered	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative), smoking cessation (lifetime max $500) and fertility (lifetime max $3,000)	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative), smoking cessation (lifetime max $500) and fertility (lifetime max $3,000)	Legally requiring prescription, plus life-sustaining drugs (lowest cost alternative)	Legally requiring prescription, plus life-sustaining drugs, smoking cessation (lifetime max $350 lifetime), fertility (lifetime max $3,000) and erectile dysfunction (max $1,000/year)	Legally requiring prescription, plus life-sustaining drugs, smoking cessation (lifetime max $350 lifetime), fertility (lifetime max $3,000) and erectile dysfunction (max $1,000/year)
• Drug Card	Yes	Yes	Yes $8.50 dispensing fee maximum	Yes $8.50 dispensing fee maximum	Yes $8.50 dispensing fee maximum

Note:
FBCE Option 1 is opt-out (i.e. no coverage provided).

Extended Health Care Benefit (Cont'd)

Current (Cont'd)

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Coinsurance on Services/Supplies	100%	100%	60%	80%	100%
Private Duty Nursing	$25,000 per person per 3 years	$50,000 per person per 3 years	60%; $25,000 lifetime	80%; $25,000 lifetime	100%; $25,000 lifetime
Hearing Aids	No coverage	$750 / 5 years	60% Children only: $500 / 5 years	80%; $500 / 5 years	100%; $500 / 5 years
Vision Care	No coverage		No coverage		
• Coinsurance		100%		80%	100%
• Eyeglasses / contacts		$300 / 24 months		$150 / 24 months	$250 / 24 months
• Eye exams		1 exam / year		$100 / 24 months	$100 / 24 months
• Laser eye surgery		Included in eyeglasses / contacts coverage		No coverage	No coverage
Paramedical Services:	No coverage		No coverage		
• Physiotherapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Massage Therapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Chiropractor		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Naturopath		No coverage		80%; $250 / year	100%; $400 / year
• Speech Therapist		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Psychologist		100%; $500 / year		80%; $250 / year	100%; $400 / year

Extended Health Care Benefit (Cont'd)

Current (Cont'd)

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
• Podiatrist/chiropodis		100%; $500 / year		80%; $250 / year	100%; $400 / year
• Acupuncturist		No coverage		80%; $250 / year	100%; $400 / year
• Dietician		No coverage		80%; $250 / year	100%; $400 / year
Orthopedic Shoes	No coverage	$150 / year per person	No coverage	80%; $400 / year adult; $200 / year child	100%; $500 / year adult; $300 / year child
Orthotics	No coverage	$150 / year per person	No coverage	80%; $200 / 24 months	100%; $400 / 24 months
Out of Country Emergency	100%	100%	100%	100%	100%
Overall Maximum	$1 million per incident	$1 million per incident	$1 million lifetime	$1 million lifetime	$1 million lifetime

Note:

FBCE Option 1 is opt-out (i.e. no coverage provided except for emergency out of county and travel assistance).

Extended Health Care Benefit

Proposed

Benefit	Option 2	Option 3	Option 4
Deductible	$100	$0	$0
Hospital			
• Semi–Private	60%	80%	100%
• Convalescent Hospital	Not covered	Not covered	Not covered
Prescription Drugs			
• Coinsurance	60%	80%	100%
• Drugs Covered	Formulary*	Formulary* plus contraceptives, smoking cessation (lifetime maximum $350) and fertility drugs (lifetime maximum $3,000)	Formulary* plus contraceptives, smoking cessation (lifetime maximum $350) and fertility drugs (lifetime maximum $3,000)
• Drug Card	Yes - $8.50 dispensing fee maximum	Yes - $8.50 dispensing fee maximum	Yes - $8.50 dispensing fee maximum

*Formulary to be determined

Note:
Option 1 is opt-out; (i.e.: no coverage except for emergency out of country and travel assistance)

Extended Health Care Benefit (Cont'd)

Proposed (Cont'd)

Benefit	Option 2	Option 3	Option 4
Coinsurance on Services/Supplies	60%	80%	100%
Private Duty Nursing	$15,000 / year	$20,000 / year	$25,000 / year
Hearing Aids	60% Children only; $500 / 5 years	80%; $500 / 5 years	100%; $500 / 5 years
Vision Care	No coverage		
• Coinsurance		80%	100%
• Eyeglasses / contacts		$150 / 24 months	$250 / 24 months
• Eye exams		$100 / 24 months	$100/ 24 months
• Laser eye surgery		No coverage	No coverage
Paramedical Services:	No coverage		
• Physiotherapist		80%; $250 / year	100%; $400 / year
• Massage Therapist		80%; $250 / year	100%; $400 / year
• Chiropractor		80%; $250 / year	100%; $400 / year
• Naturopath		80%; $250 / year	100%; $400 / year
• Speech Therapist		80%; $250 / year	100%; $400 / year
• Psychologist		80%; $250 / year	100%; $400 / year
• Podiatrist/chiropodist		80%; $250 / year	100%; $400 / year
• Acupuncturist		80%; $250 / year	100%; $400 / year
• Dietician		80%; $250 / year	100%; $400 / year

Extended Health Care Benefit (Cont'd)

Proposed (Cont'd)

Benefit	Option 2	Option 3	Option 4
Orthopedic Shoes	No coverage	$400 / 2 years adult; $200 / 2 years child	$500 / 2 years adult; $300 / 2 years child
Orthotics	No coverage	$200 / 24 months	$400 / 24 months
Out of Country Emergency maximum	100%	100%	100%
Overall Maximum	$1 million lifetime	$1 million lifetime	$1 million lifetime

Note:

Proposed Option 1 is opt-out (i.e. no coverage provided except for emergency out of county and travel assistance).

Dental

Current

Benefit	FBC Option 1	FBC Option 2	FBCE Option 2	FBCE Option 3	FBCE Option 4
Deductible	$0	$0	$0	$0	$0
Coinsurance					
• Basic	100%	100%	60%	90%	100%
• Major	No coverage	50%	50%	70%	80%
• Orthodontia	No coverage	50% (Children only)	No coverage	50%	60%
Maximum					
• Basic	1 exam / year and up to 8 units of scaling / year	2 exams / year and up to 16 units of scaling / year	$1,500 / year combined with Major	$2,500 / year combined with Major	$3,000 / year combined with Major
• Major	N/A	$1,500 / year per person	$1,500 / year combined with Basic	$2,500 / year combined with Basic	$3,000 / year combined with Basic
• Orthodontia	N/A	$3,000 lifetime / child	N/A	$3,000 lifetime	$3,500 lifetime

Note:
Option 1 for FBCE is opt-out (i.e. no coverage provided).

Dental

Proposed

Benefit	Option 2	Option 3	Option 4
Deductible	$0	$0	$0
Coinsurance			
• Basic	60%	90%	100%
• Major	50%	70%	80%
• Orthodontia	No coverage	50%	60%
Maximum			
• Basic	$1,500 per year combined with Major	$2,500 per year combined with Major	$3,000 per year combined with Major
• Major	$1,500 per year combined with Basic	$2,500 per year combined with Basic	$3,000 per year combined with Basic
• Orthodontia	N/A	$3,000 lifetime	$3,500 lifetime

Note:
Option 1 is opt-out (i.e. no coverage provided).

Paid Time Off and Other Benefits

Current

Benefit	FBC – Current	FBCE – Current	Proposed
Vacation Schedule			
	Years of Service / Vacation Days <1 / up to 15 days 1 - 6 / 15 7 - 15 / 20 16 - 24 / 25 25+ / 30	Years of Service / Vacation Days <1 / up to 15 days 1 - 7 / 15 8 - 17 / 20 18 - 24 / 25 25+ / 30	• Proposals A and B: Same as FBCE • Proposals C and D: Same as FBC
Carry Forward	Not permitted	May carry forward 5 days per year to a maximum bank of 10 days	May carry forward 5 days per year to a maximum bank of 10 days
Purchased days in flex plan	Not available	Employees may purchase up to 10 days off per year using Power Credits	Employees may purchase up to 10 days off per year using Power Credits
Statutory Holidays	10 company scheduled holidays plus 2 employee scheduled holidays	11 company scheduled holidays	• Proposals A and B: 11 company scheduled holidays • Proposals C and D: 10 company scheduled holidays plus 2 employee scheduled holidays
Earned Days Off (EDO)	Employees may earn up to 12 EDOs per year by working longer hours	Employees may earn 17 scheduled EDOs by electing to work a longer core day	Employees may earn up to 12 EDOs per year by working longer hours
Employee Assistance Plan			
Provided	Yes	Yes	Yes

Post-Retirement Benefit Program Design

Current Plans

- FBC's post-retirement benefits (PRB) program has been in a state of evolution for several years:
  - Previous program provided insured-style benefits for life
  - FBC considered moving to a defined contribution style health spending account (HSA) allocation of $2,000 per year for life
  - Eventually, FBC opted to continue active EHC, dental and MSP coverage to age 65 with no benefits after 65
- Effective January 1, 2004, FBCE implemented a new PRB program
  - The new program was voluntary for employees retiring during 2005
  - Commencing January 1, 2006 the program is mandatory for all newly retiring employees
  - The new program consists of the following benefits:
    - HAS allocation of $2,500 per year
    - High-deductible "security" extended health program
    - Life insurance

Overview

Current & Proposed

	FBC – Current[1]	FBCE – Current	Proposed
Eligibility	Age 55 with 10 years of service	Full time employees retiring on/after age 55 with 10 years of service	Full time employees retiring on/after age 55 with 10 years of service
Annual HSA Allocation	N/A	$2,500	$2,500
"Security" Extended Health Care Plan Provided?	N/A	Yes	Yes
Continuation of active EHC dental coverage?	Yes, to age 65	No	No
Provincial MSP premiums paid?	Yes, to age 65	No	No
Life Insurance	None	$10,000	$10,000
Survivor Coverage	Coverage continues to spouse until employee would have attained age 65	Security plan and 50% of HSA amount provided for lifetime of surviving spouse*	Security plan and 50% of HSA amount provided for lifetime of surviving spouse*

* HSA reduced by 50% at January 1 following the death of the retiree

Note:

1 As directed by FBC, the PRB program described here does not reflect the benefits currently valued for the company's financial statements. The benefits valued for the financial statements are as follows:

– Health Spending Account of $2,000 / year; and

– Provincial MSP premiums.

Post-retirement Benefit Transition & Implementation

- Legal
  - FBC should seek legal review of all active employee communications and notice period to ensure that there will be a low risk of legal challenge from modifying the program
  - The proposed program is likely more generous than the current PRB program for FBC employees, so this risk may not be a major concern
- Governance
  - Need to develop a plan text that describes the post-retirement benefits, eligibility, and key administrative rules, such as:
    - adding new dependents,
    - survivor coverage,
    - implications of opting out,
    - confirming eligibility each year,
    - process for issuing T4A for provincial medical premiums
- Communication
  - Communicate plan to employees and update communication materials
- Administration
  - Develop implementation plan with insurers to ensure appropriate claims eligibility classes & divisions are established

Benchmarking Analysis

Appendices

Peer Group

Appendix I

- ATCO Group
- BC Hydro
- Canadian Pacific Railway
- Capital Power Corporation
- Catalyst Paper
- Chevron
- ConocoPhillips
- Enbridge Gas Distribution
- ENMAX
- EPCOR
- Finning (Canada)
- FortisAlberta
- Insurance Corporation of BC
- Manitoba Hydro
- Methanex
- Nexen
- Spectra Energy
- Suncor
- Teck Resources
- TELUS
- TransAlta
- TransCanada PipeLines

Methodology

Appendix II

Valuation of Pensions and Benefits

- Pension and benefits data have been obtained using BENVAL® from Towers Watson's Canadian Benefits Data Source (BDS). The BDS contains detailed information on benefit programs offered by approximately 475 Canadian employers.
- BENVAL® is Towers Watson's methodology used to develop comparative values for the benefit plans provided by a group of companies. This methodology determines values using a standard set of actuarial methods and assumptions applied to a common employee population.
- To develop such values, benefits are initially analyzed in terms of when they become payable.
  - Those benefits payable in the future – defined benefit pension plans and post-retirement benefits – are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (Projected Unit Credit with service prorate method).
  - Those benefits potentially payable over the current year – defined contribution pension plans, pre-retirement death, disability benefits, and vacations and holidays – are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost method).
  - For health care and dental care coverage, the Term Cost method is based on the expected premium rate charged by an insurer for the coverage.
  - No other benefits are valued – parental leave and employee assistance programs for instance.
- The employer provided value is determined by deducting employee contributions from the total value.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

- An explanation of how each benefit plan is valued follows:

Defined Benefit Pension Plans

- The following elements are considered in determining comparative values for defined benefit pension plans: normal and early retirement benefits, disability benefits, pre- and post-retirement death benefits, termination benefits, and post-retirement pension adjustments.
- Post retirement pension adjustments are valued according to plan provisions or the actual company's policy when not stated in plan provisions.
- When a plan offers the possibility to switch between a defined contribution pension plan and a defined benefit pension plan, employees are deemed to select the defined contribution pension plan if they are younger than age 45 and the defined benefit pension plan at age 45. When an employee is hired after the attainment of age 45, he is deemed to participate in the defined benefit pension plan during his entire career.
- Plans are valued in accordance with the legislation where the plan is registered.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Defined Contribution Pension Plans, Savings, Profit Sharing, and Stock Purchase Plans

- Plans are valued by determining employee and employer contributions made during the year of valuation.
- Employee contributions are adjusted to reflect savings opportunity depending on available income and level of employer match.
- Contribution levels to Profit Sharing plans are determined by taking the average of the actual past five years' contributions to the plan.

Life Insurance Plans

- Values for the following benefits are calculated: pre- and post-retirement group life insurance, accidental death and dismemberment benefits, and survivor income benefits.
- The amount of optional insurance elected is based on the level of company provided coverage and salary.

Disability Plans

- Short-term disability benefits include salary continuance and sickness plans.
- Values are determined according to specific plan provisions including waiting periods and benefit coordination.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Health Care and Dental Care Plans

- Values are generated for pre- and post-retirement coverage. Post-retirement premiums are increased to reflect future inflation.
- Values are determined based on plan deductibles, coinsurance, and maximums as well as eligibility requirements.
- Vision care and hearing aid benefits are included in the Health Care plan value whether they are covered under the Health Care plan or a separate plan.
- Amounts allocated to the Health Care Spending Account are also included in the Health Care plan value.
- The provincial health care premiums are not included in the valuation.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Vacation and Holidays

- The value for vacation is determined based on the number of vacation days available. This includes bonus days when applicable. The number of days are determined in accordance with the company's schedule which is, usually, based on the employees' number of years of service.
- When the plan does not allow for the payment of unused vacation days during employment, we assume that employees with more than four weeks of vacation will forfeit some vacation days at the end of each year.
- The value for holidays is determined based on the number of holidays available. This includes all regular scheduled holidays and personal days.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Flexible Benefits

- The value determined for these benefits is based on the highest enrolled option for each plan.
- When not determined by the plan design, flexible benefit credits are allocated in the following order: health and dental care benefits, life insurance benefits, and disability benefits.

Methodology

Appendix II

Summary of Common Employee Population

AGE (% Female)		COMPLETED YEARS OF CREDITED SERVICE							
		Less than 1	1	2 - 4	5 - 9	10 - 19	20 - 29	30 or More	Total
0 - 19 (46%)	Number	1							1
	Avg. Base Pay	$ 29,000							$ 29,000
20 - 24 (42%)	Number	98	80						178
	Avg. Base Pay	$ 41,000	$ 41,000						$ 41,000
25 - 29 (40%)	Number	217	176	409	85				887
	Avg. Base Pay	$ 50,000	$ 50,000	$ 50,000	$ 52,000				$ 50,192
30 - 34 (40%)	Number	229	186	432	386	145			1,378
	Avg. Base Pay	$ 56,000	$ 56,000	$ 56,000	$ 59,000	$ 58,000			$ 57,051
35 - 39 (40%)	Number	218	177	411	493	534			1,833
	Avg. Base Pay	$ 58,000	$ 58,000	$ 58,000	$ 57,000	$ 60,000			$ 58,314
40 - 44 (40%)	Number	176	143	332	384	632	262		1,929
	Avg. Base Pay	$ 61,000	$ 61,000	$ 61,000	$ 62,000	$ 71,000	$ 70,000		$ 65,698
45 - 49 (40%)	Number	110	90	209	294	445	427		1,575
	Avg. Base Pay	$ 60,000	$ 60,000	$ 60,000	$ 64,000	$ 69,000	$ 74,000		$ 67,085
50 - 54 (40%)	Number	75	61	141	166	317	391	158	1,309
	Avg. Base Pay	$ 67,000	$ 67,000	$ 67,000	$ 61,000	$ 68,000	$ 75,000	$ 77,000	$ 70,078
55 - 59 (37%)	Number	26	21	50	95	188	172	135	687
	Avg. Base Pay	$ 57,000	$ 57,000	$ 57,000	$ 61,000	$ 64,000	$ 72,000	$ 91,000	$ 69,905
60 + (30%)	Number	9	7	16	28	76	51	36	223
	Avg. Base Pay	$ 66,000	$ 66,000	$ 66,000	$ 52,000	$ 62,000	$ 69,000	$ 81,000	$ 65,987
Total	Number	1,159	941	2,000	1,931	2,337	1,303	329	10,000
	Avg. Base Pay	$ 55,912	$ 55,931	$ 57,313	$ 59,708	$ 66,036	$ 73,036	$ 83,182	$ 62,421

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Economic Factors	
Valuation interest rate	7.0% per year
Salary escalation	4.0% per year
Escalation of Year's Maximum Pensionable Earnings	3.0% per year
Inflation	2.5% per year
Increase in medical and dental premiums for post-retirement benefits valuation	4.0% per year

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Demographic Factors	
Mortality	• 1994 Uninsured Pensioner mortality without margins and 25 years of mortality improvement
Disability • STD • LTD • Other plans	• Based on Commissioner's Disability Table, the Society of Actuaries TSA Group Table, and Towers Perrin's experience • Society of Actuaries 1981 Report on Mortality and Morbidity Experience, with adjustment • None
Termination of Employment	See table on next page
Retirement	See table on next page
Employee/family status	Employees are assumed to be married. Female spouses are assumed to be three years younger than male spouses. Employees are assumed to elect family coverage. Family is assumed to consist of two adults and two children.

Methodology

Appendix II

Valuation of Pensions and Benefits (cont'd)

Termination of Employment

Age at Termination	Termination Rate
20 - 24	15% each year
25 - 30	10% each year
31 - 45	Starts at 9.5% at age 31 and reduced by 0.5% each age
46 - 54	2% each year
55 +	0% each year

Illustrative Probability of Retirement

Age at Retirement	Age of Unreduced Benefit			
	65	62	60	55
50	2%	2%	2%	2%
55	4%	4%	4%	15%
60	10%	10%	15%	15%
62	20%	30%	30%	50%

For example, under a plan that provides an unreduced benefit at age 62, 30% of active employees will retire at age 62.

Attachment 223.1

Letter of Understanding #3
Between
Terasen Gas Inc.
(Customer Services Centres)
And
Canadian Office and Professional Employees Union, Local 378

Re: Market Competitiveness

The parties agree that in order to ensure the long term viability of the Customer Care Business Unit it is critical that the total compensation package for employees remain competitive with other similar customer care entities. This will support our shared objectives of:

- Being able to attract and retain qualified employees
- Maintaining cost competitiveness and sustainability on an ongoing basis

Meeting these objectives is in the best interest of the Union, the Company and our Customers. As such the parties agree that a joint market comparator survey will be conducted in advance of the expiry of the collective agreement or as otherwise agreed by the parties, and that such survey will evaluate all key elements of total compensation including base wages, incentive pay, paid time off, pensions and benefits.

It is further agreed that an appropriate comparator group would include the following companies:

- Accenture Business Services
- Aeroplan
- BCAA
- Coast Mountain Bus Company
- Rogers
- Shaw
- Telus

The parties may change this list of companies by mutual agreement

For Terasen Gas	For COPE, Local 378
Jeff Marwick	Kevin Smyth
Manager, Labour Relations	Union Representative

Aug/19/09
Date

Attachment 223.1.1

Canadian Electricity Association | Association canadienne de l'électricité

CEA Quick Poll: Powerline Rates - February 2012

What is your 2012 base rate ($/hr) for the Powerline Technician classification?

FortisBC	Northwest Territories Power Corporation	AltaLink
The FortisBC IBEW Collective agreement was a five year agreement, expiring on January 31, 2013. Effective February 1, 2012, the Powerline technician base rate of pay is $39.91/hour.	Our collective agreement expired in 2011 and we do not have 2012 rates at this time. We have a five-step salary grid for PLT - $37.98 to $46.17 per hour, plus a $2.40 per hour temporary market supplement. The supplement is paid on regular hours only (not OT hours).	At AltaLink our 2012 Fully Qualified Transmission Lineman base rate is 41.73/hr. There are three step levels: $41.73/$43.49/$45.23. Progression is every 6 mths with satisfactory performance.
Yukon Energy	**Nova Scotia Power**	**Saint John Energy**
$35.09 – 41.29 per hour.	Our Journeyperson PLTs currently earn $34.38 per hour and their contract expires on March 31, 2012.	Our 2012 base rate for Powerline Technicians is $35.76 per hour, this will be in place until March 31, 2013 at which time our present contract expires.
BC Hydro	**Toronto Hydro**	**Manitoba Hydro**
BC Hydro's PLT hourly rate is $37.96.	Our equivalent is a Certified Power Line Person at $40.26.	The current Powerline Technician maximum base hourly rate at Manitoba Hydro is $37.05.
Nalcor Energy	**City of Medicine Hat**	**NB Power**
Line Worker A with Newfoundland and Labrador Hydro - $34.94/hour effective April 1, 2012.	Our rate is $46.29 as of Jan 01, 2012.	The NB Power Powerline Technician (PLT) and Lead Powerline technician hourly rates effective January 1 2012 are below. Our PLT's work 40 hours per week and are part of the IBEW union. This is the last increase for the current collective agreement which expires December 31 2012. While negotiations have not started, as a Crown Corporation NB Power has been mandated by the provincial government for all employees to serve two years of zero percent increases. This means that as collective agreements become open for negotiations, two zero years are to be negotiated. Therefore, it is anticipated that the first two years of the next collective agreement will contain 0% increases. Powerline Technician Step A $34.49 Step B $35.76 Lead Powerline Technician $38.62

IBEW Wage Comparators

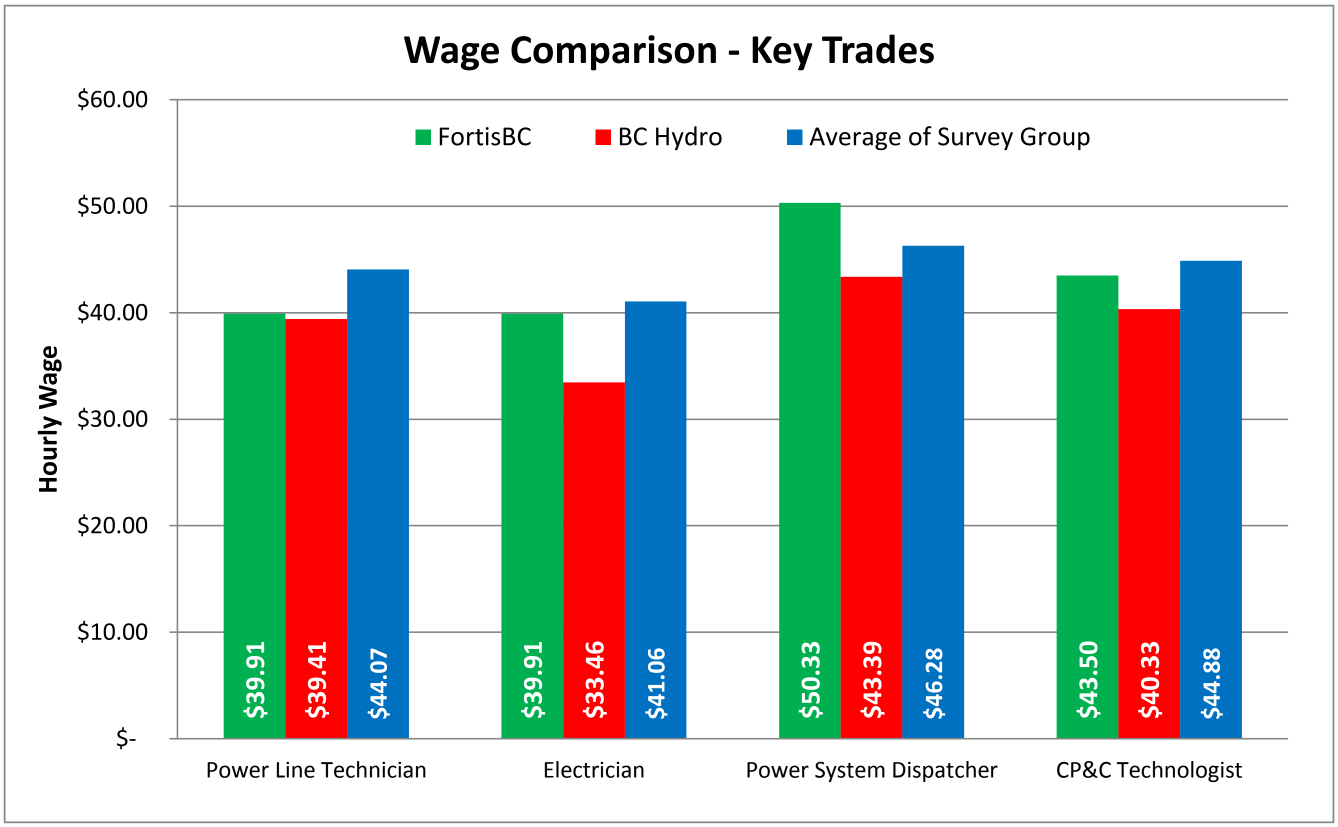
	FBC	Average of Survey Group	Sample Size	Enmax	Epcor (2012)	Trans Alta (2013)	Sask Power	Manitoba Power	Alta Link	Atco Electric	Fortis Alberta (2013)	BC Hydro	Line Contractors Assoc (2013)			
Power Line Technician	$ 39.91	$ 44.07	7		$ 47.56		$ 42.35	$ 38.73	$ 45.23		$ 48.51	$ 39.41	46.67	$ 44.07	7	41.00216
Electrician	$ 39.91	$ 41.06	6		$ 42.45	$ 44.45	$ 41.86	$ 38.92	$ 45.23			$ 33.46		$ 41.06	6	34.81178
Power System Dispatcher	$ 50.33	$ 46.28	5		$ 47.15	$ 49.52	$ 46.62	$ 44.71				$ 43.39		$ 46.28	5	45.14296
CP&C Technologist	$ 43.50	$ 44.88	5		$ 44.56	$ 47.96	$ 44.71		$ 46.83			$ 40.33		$ 44.88	5	41.95933
Crew Lead (dual trades)	$ 48.29	$ 48.42	4		$ 50.52	$ 51.84	$ 46.55					$ 44.77		$ 48.42	4	46.57871
Crew Lead (Foreman)	$ 44.30	$ 47.35	6		$ 49.30		$ 44.04		$ 49.68		$ 50.43	$ 40.83	49.82	$ 47.35	6	42.47953
Mechanic	$ 39.91	$ 40.00	4		$ 42.45		$ 40.90					$ 34.65	41.99	$ 40.00	4	36.04986
Warehouseman	$ 32.14	$ 32.75	5			$ 33.53	$ 38.79		$ 31.33		$ 33.02	$ 27.10		$ 32.75	5	28.19484
Safety Coordinator	$ 45.09	$ 45.83	2		$ 47.56		$ 44.09							$ 45.83	2	0
PLT 3					$ 44.56									$ 44.56	1	
Power Electrician 1					$ 44.56	$ 44.45								$ 44.51	2	
Trades					$ 42.45		33.38							$ 37.92	2	
Leadhand					$ 47.31									$ 47.31	1	
Electrical System Control Operator					$ 47.15		40.32							$ 43.74	2	
Senior Electrical System Control Operator					$ 49.52									$ 49.52	1	
Electrical System Control Operator Foreman					$ 51.99									$ 51.99	1	
Safety Coordinator							34.91							$ 34.91	1	
Crew Lead Wearhouse											$ 40.79			$ 40.79	1	

Company	**2010**	**2011**	**2012**	**2013**	**2013**	**2013**
FortisBC	4.00%	5.00%				
Alta Link	2.50%	3.00%	3.00%			
Epcor		3.00%	3.00%			
Fortis Alberta		3.00%	3.00%	4.00%		
Line Contractors Assoc		1.00%	2.50%	2.75%		
Sask Power	1.50%	2.00%	2.25%			
Manatoba Hydro				0.00%	2.75%	2.75%
Trans Alta	2.00%	2.00%	2.00%	3.75%		
FortisBC Energy Inc		2.00%	2.00%	2.00%		
Spectra Energy Transmission			3.00%	3.25%		
Average (exl FBC)	**2.00%**	**2.29%**	**2.59%**	**2.63%**	**2.75%**	**2.75%**

Other Settlements	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Air Canada (Cargo Ops)			0.00%	0.00%	2.00%	3.00%	3.00%
Air Canada (Tech Services / Logistics)			2.00%	2.00%	2.00%	3.00%	3.00%
CN Railway (Locomotive Engineers)			3.00%	3.00%	3.00%		
Rio Tinto Alcan - Kitimat			3.00%	2.50%	2.50%	2.50%	3.00%
Tech Resources			4.00%	4.00%	4.00%	4.00%	
Tech Coal Limited			4.00%	4.00%	4.00%		

Trade	FortisBC	BC Hydro	Average of Survey Group	Sample Size
Power Line Technician	$ 39.91	$ 39.41	$ 44.07	7
Electrician	$ 39.91	$ 33.46	$ 41.06	6
Power System Dispatcher	$ 50.33	$ 43.39	$ 46.28	5
CP&C Technologist	$ 43.50	$ 40.33	$ 44.88	5
Crew Lead (dual trades)	$ 48.29	$ 44.77	$ 48.42	4
Crew Lead (Foreman)	$ 44.30	$ 40.83	$ 47.35	6
Mechanic	$ 39.91	$ 34.65	$ 40.00	4
Warehouseman	$ 32.14	$ 27.10	$ 32.75	5
Safety Coordinator	$ 45.09	$ -	$ 45.83	2

*BC Hydro rates are 2010 as their contract has not yet been re-negotiated.



Attachment 226.1.1

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June 3, 2013

Ms. Jody Drope
Chief Human Resources Officer
FortisBC
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Dear Jody:

Re: Response to BCUC Directive - Executive Compensation Review

Hay Group Limited ("Hay Group") has been retained by FortisBC to conduct a competitive review of its executive compensation as part of the response to the BCUC Directive. To fulfill this mandate, we benchmarked the total compensation package of nine executive roles against the market.

Hay Group and Executive Compensation Review

Hay Group is a global management consulting firm with over 50 years of experience providing independent executive compensation advisory services to companies in a wide variety of industries and corporate structures in Canada. We have the most comprehensive pay database in the country, backed by the world's leading methodology in determining the complexity of roles.

Further details are set out in our report Executive Compensation Review, May 2013, which includes benchmarking information on all elements of FortisBC's executive compensation as well as a discussion of whether the SERP is incentive-based or handled as a benefit, and how the 13 percent for SERP compares to amounts offered by comparable companies.

Summary of Findings

Based on our review, we observe a gap from market median in target total direct compensation for all executives of FortisBC against the Hay Group Commercial Industrial database. Base salary and target total cash are generally positioned around market median, but a significant loss of competitiveness is evident at target total direct level, primarily due to weakness in LTI compensation.

To address this evident compensation gap, FortisBC has implemented a Performance Share Unit ("PSU") plan supplementing the current LTI plan with effect from 2013. From our review of market practices, the use of PSUs has become more prevalent among Canadian utilities and general industry as they seek to align executive compensation with long-term sustained corporate performance. Based on our benchmarking exercise and understanding of the PSU plan, it is our view that this plan will assist in closing the compensation policy gap to market median.

Jody, I trust the accompanying report is of assistance to you. I will be happy to answer any questions that may arise.

Sincerely,
Hay Group Limited

Christopher A. Chen, LLB
National Director, Executive Compensation

cc: Kennedy Lee, Hay Group Limited

Executive Compensation Review
FortisBC

Prepared by:
Christopher A. Chen

May 2013

Introduction

- Hay Group Limited ("Hay Group") has been retained by FortisBC to conduct a competitive review of its executive compensation
- Specifically, this review includes:
  - Benchmarking information on all elements of FortisBC's executive compensation
  - Discussion of whether the SERP is incentive-based or handled as a benefit, and how the 13 percent for SERP compares to amounts offered by comparable companies

Contents

HayGroup®

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Methodology

Methodology

- Hay Group compared the compensation data of 9 FortisBC executives (below) to roles of similar size and scope in a broad reference group of approximately 250+ Canadian commercial industrial companies

FortisBC Role
President & CEO
EVP HR, Customer & Corporate Services
EVP Network Services, Engineering & Generation
VP Energy Solutions & External Relations
VP Energy Supply & Resource Development
VP Finance & CFO
VP Strat Plan, Corp Dev & Reg Affairs
VP Operations Support, Gen Counsel & Corp Sec
VP Customer Service

- Role size and scope were determined using the Hay Group Guide Chart – Profile Method^{SM} of job evaluation
  - This method measures three different aspects of job content (know-how, problem-solving, and accountability) to determine the value for the whole job, expressed in "Hay Points"

Methodology

- FortisBC compensation data was then compared to the market for the following elements of compensation:
  - Base salary (actual)
  - Target and actual short-term incentive ("STI") (as % base salary)
  - Target and actual total cash (base salary plus target or actual STI, respectively)
  - Present value of long-term incentive ("LTI") (as % base salary)
  - Target and actual total direct compensation (target or actual total cash plus LTI, respectively)
- Market data values are as of 2012, as 2013 data is not yet available. To maintain consistency with market values, FortisBC roles' 2012 base salaries and 2011 actual STI payouts were used for benchmarking
- The competitiveness of FortisBC's supplemental retirement arrangement ("SERP") was also assessed relative to the market

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02

Summary of observations

Summary of observations

- We observe that FortisBC's target total direct compensation (base salary plus target short- and long-term incentives) is below market median for all roles
  - Base salary and target total cash are generally positioned around market median
  - As such, this positioning is heavily impacted by weakness in the competitiveness of long-term incentive ("LTI") compensation
- However, in actual total direct compensation this shortfall in LTI is somewhat moderated by the strong actual short-term incentive ("STI") payouts which position most FortisBC executives close to market median
- As actual values may vary from one year to another, we would recommend using target values for compensation planning, as they represent payouts at expected performance levels and as such will provide a more consistent baseline for assessing market competitiveness

Summary of observations

	Actual Base Salary	Target Compensation: STI (as % Base)	Target Total Cash	LTI (as % Base)	Target Total Direct	Actual Compensation: STI (as % Base)	Actual Total Cash	LTI (as % Base)	Actual Total Direct
President & CEO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EVP HR, Customer & Corporate Services	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EVP Network Services, Engineering & Generation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Energy Solutions & External Relations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Energy Supply & Resource Development	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Finance & CFO	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Strat Plan, Corp Dev & Reg Affairs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Operations Support, Gen Counsel & Corp Sec	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
VP Customer Service	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Summary of observations

Base Salary

- Base salaries for FortisBC executives are generally positioned around the market median, ranging from P40 to P57

Target Total Cash (Base Salary + Target STI)

- Target total cash is close to median for most roles, with a few falling near the 40^{th} percentile

Target Total Direct Compensation (Target Total Cash + LTI)

- Target total direct compensation falls below the median for all FortisBC executive roles, with four roles falling below the 40^{th} percentile
- LTI grants show significant weakness compared to the market, with all values falling at or below the 17^{th} percentile

Summary of observations

Actual Total Cash (Base Salary + Actual STI)

- Actual total cash 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 STI above the 70th percentile

Actual Total Direct Compensation (Actual Total Cash + LTI)

- The strong STI values driving competitive total cash are largely mitigated by weak LTI compensation, resulting in actual total direct compensation generally around market median

03

Analysis by position

President & CEO

President & CEO
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
President & CEO	**$520,000**	**50%**	**$780,000**	**52%**	**$1,048,900**	**82%**	**$945,000**	**52%**	**$1,214,000**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]					[redacted]	[redacted]		
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 400% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

EVP HR, Customer & Corporate Services

HayGroup®

EVP HR, Customer & Corporate Services
FortisBC
Hay Points: [redacted]

CDN $		Target Compensation				Actual Compensation			
	Actual Base Salary	**STI (as % Base)**	**Target Total Cash**	**LTI (as % Base)[1,2]**	**Target Total Direct**	**STI (as % Base)**	**Actual Total Cash[2]**	**LTI (as % Base)[2]**	**Actual Total Direct**
EVP HR, Customer & Corporate Services	**$290,000**	**40%**	**$406,000**	**19%**	**$462,200**	**66%**	**$480,000**	**19%**	**$536,300**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]		[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

EVP Network Services, Engineering & Generation

EVP Network Services, Engineering & Generation
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
EVP Network Services, Engineering & Generation	**$264,000**	**40%**	**$369,600**	**19%**	**$420,800**	**63%**	**$429,000**	**19%**	**$480,200**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]					[redacted]	[redacted]		
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

VP Energy Solutions & External Relations

VP Energy Solutions & External Relations
FortisBC
Hay Points: [redacted]

CDN $

		Target Compensation				Actual Compensation			
	Actual Base Salary	STI (as % Base)	Target Total Cash	LTI (as % Base)[1, 2]	Target Total Direct	STI (as % Base)	Actual Total Cash [2]	LTI (as % Base)[2]	Actual Total Direct
VP Energy Solutions & External Relations	$275,700	40%	$386,000	19%	$439,500	62%	$445,700	19%	$499,200
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]		[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

VP Energy Supply & Resource Development

VP Energy Supply & Resource Development
FortisBC
Hay Points: [redacted]

CDN $

		Target Compensation				Actual Compensation			
	Actual Base Salary	STI (as % Base)	Target Total Cash	LTI (as % Base)[1, 2]	Target Total Direct	STI (as % Base)	Actual Total Cash [2]	LTI (as % Base)[2]	Actual Total Direct
VP Energy Supply & Resource Development	**$258,500**	**40%**	**$361,900**	**19%**	**$412,000**	**58%**	**$408,500**	**19%**	**$458,600**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

VP Finance & CFO

VP Finance & CFO
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
VP Finance & CFO	**$243,600**	**40%**	**$341,000**	**19%**	**$388,200**	**62%**	**$393,600**	**19%**	**$440,900**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

VP Strategic Planning, Corporate Development & Regulatory Affairs

VP Strat Plan, Corp Dev & Reg Affairs
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
VP Strat Plan, Corp Dev & Reg Affairs	**$243,600**	**40%**	**$341,000**	**19%**	**$388,200**	**62%**	**$393,600**	**19%**	**$440,900**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]	[redacted]	[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

VP Operations Support, General Counsel & Corporate Secretary

VP Operations Support, Gen Counsel & Corp Sec
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
VP Operations Support, Gen Counsel & Corp Sec	**$237,700**	**35%**	**$320,900**	**19%**	**$367,000**	**53%**	**$362,700**	**19%**	**$408,800**
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]					[redacted]	[redacted]		
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 150% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

HayGroup®

VP Customer Service

VP Customer Service
FortisBC
Hay Points: [redacted]

CDN $	Actual Base Salary	Target Compensation: STI (as % Base)	Target Compensation: Target Total Cash	Target Compensation: LTI (as % Base)[1, 2]	Target Compensation: Target Total Direct	Actual Compensation: STI (as % Base)	Actual Compensation: Actual Total Cash [2]	Actual Compensation: LTI (as % Base)[2]	Actual Compensation: Actual Total Direct
VP Customer Service	[redacted]								
Canadian Commercial Industrial Market[3]									
P90	[redacted]								
P75	[redacted]								
Median (P50)	[redacted]								
P25	[redacted]								
P10	[redacted]								
Average	[redacted]								
Variance from Median	[redacted]		[redacted]			[redacted]	[redacted]		[redacted]
Market Position	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. LTI% for FortisBC represents target fair value based on an award of stock options reflecting 100% of Base Salary
2. FortisBC' stock options have been present valued at 12.93% using the binomial valuation model
3. Market data is as of May 2012

04

Supplemental retirement arrangement

Supplemental retirement arrangement

- Supplemental retirement arrangement ("SERP") at FortisBC is treated as a benefit for the respective executives
- With the exception of a few individuals who have previous plan arrangements, FortisBC executives are eligible to participate in the SERP in addition to their RRSP
- Specifically, the SERP provides for the accrual of 13% of earnings <u>in excess of</u> the Income Tax Act RRSP limit

Supplemental retirement arrangement

- For a median executive with an annual earnings of $361,900, the total employer contribution of the two plans (i.e., RRSP + SERP) would amount to effectively 9.8% of the incumbent's earnings as illustrated in the calculation below

Median Executive Annual Retirement Benefit Calculation

		RRSP		SERP
	Annual Earnings	Employee [1] Contribution	Employer [2] Contribution	Employer [3] Contribution
Median Executive	361,900	11,485	11,485	24,077

Total Employer Contribution:	35,562
As % of Earnings:	9.8%

Notes:

1. Employee matching contribution (6.5% of earnings) up to the 2012 RRSP limit.

2. Employer contribution (6.5% of earnings) up to the 2012 RRSP limit.

3. Additional employer contribution (13% of earnings minus the maximum RRSP limit for the year).

- As an independent advisor, Hay Group Limited has reviewed the value of FortisBC's retirement benefits
- In our opinion, the annual total employer contribution rate of FortisBC's retirement benefits is within the norm of other executive retirement programs in the commercial industrial market

Attachment 226.2

Dennis Swanson
Director, Regulatory Affairs

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

Regulatory Affairs Correspondence Email:
electricity.regulatory.affairs@fortisbc.com

CONFIDENTIAL

July 5, 2013

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Page 120

CONFIDENTIAL

Enclosed please find Confidential page 120 of the Application for Approval of a Multi-Year Performance Based Ratemaking (PBR) Plan.

Request for Confidentiality

FBC is requesting confidentiality of certain paragraphs on page 120 of the Application containing sensitive information which, if disclosed publicly, could compromise future negotiations between the Company and its unionized labour bargaining units. The Company has submitted a redacted version for the public record.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

Dennis Swanson
Director, Regulatory Affairs

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

Regulatory Affairs Correspondence Email:
electricity.regulatory.affairs@fortisbc.com

CONFIDENTIAL

July 5, 2013

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Inc. (FBC)

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Appendix C2 Executive Compensation Benchmarking

CONFIDENTIAL

Enclosed please find Confidential Appendix C2 of the Application for Approval of a Multi-Year Performance Based Ratemaking (PBR) Plan.

Request for Confidentiality

FBC is requesting confidentiality of Appendix C2, Executive Compensation Benchmarking. Appendix C2 contains information that is not in the public domain.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Sincerely,

FORTISBC INC.

Original signed:

Dennis Swanson

Attachments

Attachment 233.3

Evaluation, Measurement & Verification Framework (DRAFT)

May 2013

Acknowledgements

The authors wish to acknowledge and express our appreciation to the many individuals who contributed to the development of the FortisBC Evaluation Measurement & Verification Framework.

Feedback and comments from FortisBC Internal Stakeholders, EEC Advisory Group members, BC Hydro, Power Sense, and Habart & Associates assisted in the development of the FortisBC Evaluation, Measurement & Verification Framework.

Table of Contents

1. INTRODUCTION

1.1 BACKGROUND

FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC Energy (Whistler) Inc. (FEW), are energy utilities providing primarily natural gas throughout most of BC. FortisBC Inc. is an integrated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia (BC). Collectively these utilities, referred to as "FortisBC" or "the Companies", have developed a framework for evaluation, measurement and verification ("EM&V") activities to examine the effectiveness of its Demand Side Management (DSM) programs. Electric DSM programs are referred to as Power Sense and natural gas DSM programs are referred to as Energy Efficiency and Conservation (EEC).

FEI, FEVI and FEW have been involved with delivering DSM programs and program evaluation since the 1990s[1]. In 2009, following BC Utilities Commission (BCUC) approval of the 2008 EEC Application, the Companies rapidly expanded their menu of natural gas EEC program offerings available to customers, along with the associated budgets. This increase in EEC programming has been followed by an increase in program evaluation activity.

As part of the ramp up in evaluation activity, the Companies recognized the need to develop an evaluation framework and have been examining various evaluation standards and practices that exist within the industry. The BCUC also recognized the need for such a framework and, in its decision with respect to the Companies' 2012-2013 Revenue Requirement Application (Order No. G-44-12), provided the following directive:

> *"The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework."*[2]

FortisBC Inc. has been implementing DSM programs and conducting program evaluation activities since 1989. While the BCUC did not specifically direct the electric utility to submit an EM&V framework, it has provided recommendations through its review of the electric utility's DSM Monitoring and Evaluation (M&E) plans. Most recently, in response to the FortisBC Inc.'s proposed DSM M&E Plan for 2012 through 2014, the BCUC recommended that FortisBC Inc.

---

[1] The Companies' earlier EEC activities were referred to in previous regulatory filings with the BCUC as Demand Side Management (DSM) activities.

[2] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/G-44-12_FEU-2012-13RR-Decision-WEB.pdf.

broaden its plan by eliminating a minimum savings target threshold to trigger an evaluation and provided some guidance on budget levels for evaluation activity based on industry norms. In their decision document (Order No. G-110-12), the BCUC stated:

> *"FortisBC outlined a possible alternative evaluation plan where every program undergoes evaluation according to the typical timing for the various evaluations described in Section 6.1.2 above. FortisBC estimates the alternative M&E plan would cost an additional $100,000 per year to implement. This would represent just over 6 percent of the Company's total DSM budget…*
>
> *…Given that FortisBC's alternative M&E plan costs $100,000 more per year and that amount remains within the California Evaluation Framework range of common budget allocations to M&E, the Commission Panel recommends that FortisBC resubmit an alternative M&E schedule, such as that submitted in response to BCUC IR 2.98.7, that does not apply a 10 Gwh threshold to trigger evaluation and that follows the typical sequence of evaluations as laid out in the M&E Plan for acceptance by the Commission…*
>
> *…The Commission Panel encourages FortisBC to supplement its own studies with data from other utilities wherever appropriate and to conduct shared evaluations on integrated programs."*[3]

Provincial and Federal regulations also influence a utilities' EM&V activities. In BC, the Demand-Side Measures Regulation, made pursuant to the Utilities Commission Act, sets out many of the definitions, cost effectiveness requirements and calculation considerations, and other demand side activity portfolio requirements for BC utilities, many of which are unique to this jurisdiction. For example, the need to consider societal costs and benefits and the methodology for assigning value to such costs and benefits are set out in the Province's Demand-Side Measures Regulation[4].

[3] BCUC decision on FortisBC Inc.'s 2012-2013 Revenue Requirement and Integrated System Plan Application, http://www.bcuc.com/Documents/Decisions/2012/DOC_31457_G-110-12_FBC-2012-13RRA_Decision-WEB.pdf.

[4] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/10_326_2008.

2. EVALUATION FRAMEWORK

2.1 PURPOSE OF THE EVALUATION FRAMEWORK

The EM&V Framework documents the background, objectives, principles and general practices that will guide the Companies approach, resources and timeframes for EM&V activities. The purpose of the Framework is to provide reliable information relating to when evaluations should be conducted, the types of evaluation that can be conducted, and a discussion of approaches for conducting those studies. It is expected that this document will be updated from time to time in consultation with industry and stakeholders as industry practices evolve and are adopted by the Companies.

The Framework is not a step by step evaluation manual, but it's a guideline that allows for flexibility yet complies with industry standards and practices. The intended audience includes government, policy staff, program managers, program planners and evaluators, and other internal and external stakeholders. Section 2.2 provides a detail explanation of the Companies' evaluation objectives and role of the framework.

2.2 EVALUATION OBJECTIVES

The Companies' have five overriding objectives for conducting evaluations on EEC programs, which include:

1. *Determining whether DSM program objectives are being met.* Program design targets and objectives are determined based on available industry sources. Evaluation activities are conducted to determine if program design targets are being met, such as the amount of energy savings, the number and nature of participants, emission reductions and other targets.
2. *Ensuring that the Companies and ratepayers are obtaining value from their DSM investments.* Evaluation results provide inputs to the cost-benefit analyses in determining the effectiveness of DSM programs. The Companies prescribed cost-benefit analyses are also defined by; the industry standards[5], provincial regulations[6], and the commission's directives.
3. *Providing feedback to program and company management on the performance of DSM programs.* Evaluations help program managers understand how their programs are performing and provide information to help them evolve their programs to be more effective, or perhaps determine if some programs should be discontinued.

---

[5] The Companies use the cost-effectiveness methodologies articulated in the *California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Programs and Projects.*

[6] The Modified Total Resource Cost Test (MTRC) is defined in the *Utilities Commission Act Demand-Side Measures Regulation*

4. *Examining the relationship between a program's activities and a market effect through the use of Market Transformation evaluation.* Evaluations are conducted to assess changes within a market that are caused, at least in part, by the energy efficiency programs attempting to change that market.
5. *Providing assurance to both internal and external stakeholders for the continued support of DSM programs.* Proper evaluation activities ensure that results from DSM programs are credible. This assurance is critical for ongoing support from:
    - External interest groups including customers, BCUC, government, First Nations, communities and other interest groups, trade allies and market participants; and
    - Internal stakeholders including senior management, departments competing for resources, departments responsible for oversight, such as finance and internal audit, and shareholders.

2.3 *EVALUATION PRINCIPLES*

The Companies will conduct their EM&V activities based on the following principles:

- All DSM programs will be evaluated on a program by program basis[7]. The type of evaluations, level of resources dedicated to each evaluation and the extent of the evaluation study will depend upon:
    - Size of investment in the DSM program being evaluated.
    - The amount of risk that a program may not meet cost effectiveness expectations.
    - The amount of data and information available on the effectiveness and evaluation of similar programs by FortisBC and elsewhere in the marketplace,
    - Budget constraints (see Section 4.1 for additional discussion on budgets).

    Subject to the same considerations as above, programs with explicit energy savings targets will have impact evaluations, unless there is a valid reason and an explicit decision is made not to do so.

- Transparency:
    - Reasons for decisions on evaluation methodologies will be documented
    - Assumptions made during the conducting of an evaluation study will be documented.
    - Evaluation activities will be auditable.

[7] DSM programs for which we do not report direct energy savings, such as Educational or Research Programs, may not be subject to the same impact evaluation activities as programs that we do report energy savings for.

- o Summaries of completed evaluations will be presented in the Companies EEC Annual Reports. Final Evaluation Reports will be made available to the BC Utilities Commission and other Stakeholders if requested.

- The use of third party evaluators
  - o External consultants may be retained to conduct evaluation activities when internal staffing resources are unavailable or external expertise are needed (See Section 4.3 for additional discussion on staffing resources)
  - o Third party evaluators are retained based a combination of the consultant's qualifications, the level of detail evaluation work required and the program size
  - o Evaluation staff and Program Managers work collectively to select the suitable external consultant. The selection process and format is determined by the evaluation staff

- The evaluation process will be integral to DSM planning:
  - o Evaluation activities will be an important consideration during portfolio and program planning, and as part of the program business case process.
  - o Early consideration of evaluation requirements help ensure that the necessary and timely data is collected throughout the program development and implementation process.

- Continuous Improvement:
  - o The Companies will continue to monitor the energy efficiency marketplace for industry best practices, standards and protocols for evaluation practices and will adopt those that make practical sense for evaluation activities in BC.
  - o The Companies will strive to become industry leaders in evaluation activities.
  - o This framework is expected to remain stable over time, but will be updated as necessary

- Timeliness
  - o The Companies will strive to conduct and complete evaluations at appropriate times within the resource constraints, and program growth it is subject to for these activities.

2.4 EVALUATION PLANS

This framework is not intended to be or to replace an evaluation plan. Evaluation Plans will be prepared by FortisBC for inclusion with the Companies applications to the BCUC for DSM funding. These plans will detail the programs that the Companies intend to evaluate, the types of evaluations the Companies intend to undertake, and general time frames for the evaluation activities during the period of the funding request. Progress made toward completing the evaluation plan, and any needed adjustments to the plan, will be provided in the Companies' Annual DSM reports.

3. TYPES OF EVALUATION STUDIES

There are a range of EM&V studies that are undertaken to evaluate FortisBC DSM programs. The type, timing and frequency of studies, and the evaluation practices implemented for each study will depend on a variety of factors including the type of program being evaluated, the level of program spending, experience with similar programs, the number of program participants, the quality of data upon which any energy savings assumptions are based, and more. For clarity, the evaluation component of EM&V refers to the broad spectrum of evaluation activities that can make up an evaluation plan while Measurement and Verification refers more specifically to the range of methodologies used to measure and verify actual energy savings from implementing a program of demand side measures. Hence measurement and verification is a subset of evaluation activities.

3.1 *Process Evaluations*

Process evaluations examine the effectiveness of program delivery. Objectives for process evaluations include improving program implementation and program delivery as well as ensuring high satisfaction levels among customers, trade allies and other program participants. Areas reviewed include incentive and rebate levels; communication and promotional initiatives; program operations and implementation; customer awareness and acceptance as a customer service (satisfaction) of energy efficient technologies and measures; and trade ally (distribution & implementation) awareness and acceptance. Process evaluations are generally first conducted within 6 to 18 months following the launch of a new program and for long duration programs on a periodic basis thereafter.

3.2 *Market Evaluations*

Market evaluations test a DSM program's effectiveness at increasing the market penetration of an efficient technology or measure. Objectives for market evaluations include measuring increases in market penetration of energy efficient technologies and assessing the share of measures attributable to the program. Market effects often have a larger impact on the adoption rate of a product or technology than they receive credit for, and taking credit for this can often negate some of the free rider impacts. Evaluation activities include:

- assessing market potential and market penetration over time through a review of the availability, accessibility and affordability of energy efficient technologies and measures,
- identifying barriers and assessing the program's effectiveness at overcoming barriers, and
- assessing how much of the remaining market the program can be expected to address.

When a market evaluation is determined to be necessary, the timing must allow a sufficient period for program implementation and uptake. These evaluations are therefore generally conducted between two and three years following a program launch.

3.3 *IMPACT EVALUATIONS*

Impact evaluations measure energy savings achieved by a DSM program. Objectives for impact studies include:

- measuring decreases in natural gas consumption,
- estimating free-rider and spill-over (market) effects to determine net savings impacts, and
- determining the cost effectiveness of the program according to a set of cost-benefit analysis based on industry and/or regulatory standards.

Impact evaluations will draw on information available from measurement and verification studies, energy consumption data (billing analysis), results of similar programs and evaluations in other jurisdictions, and/or benchmarking studies as appropriate and where such information exists. As with process evaluations, an impact evaluation may include comments on appropriateness of program design and/or suggestions for changes to increase effectiveness.

The timing of impact evaluations must allow a sufficient period of program operation for implementation and uptake, including the adoption of process improvements that might be identified during the early program period. Generally, impact evaluations are conducted between two and three years following a program's launch. However, depending on the program life cycle, impact evaluations may be conducted annually to provide a preliminary check on the engineering estimates or when findings are required to launch the program for a second year.

For some programs, impact evaluations may occur in two stages. The first stage will involve participant survey work to improve the Companies' knowledge about the implementation of individual measures, and a second stage that involves a billing or other more detailed analysis.

3.4 *PILOT STUDIES*

Pilot studies are an important component of the Companies' DSM portfolio and are conducted to provide necessary research into potential new efficiency measures or technologies in support of developing new programs or initiatives. Research objectives can include understanding how the market may respond to the introduction of a new measure, obtaining adequate performance data for a new measure (valid for local conditions), or both. FortisBC limits pilot study activity to the assessment of new efficiency measures or technologies that are market ready, but not yet widely available or adopted within BC.

Studies focused on obtaining an understanding of the market include typical market research investigations such as participant surveys. Studies focused on obtaining measure performance data include measurement and verification studies. In both cases, the pilot is used to test the idea on a small scale and hence reduce risk and cost if the program concept requires modifying prior to the launch of a full scale program or if performance results are insufficient for the development of a full program.

3.5 *MEASUREMENT AND VERIFICATION ACTIVITIES*

M&V refers to a range of activities or studies used to determine the performance of an installed DSM measure. M&V activities are most often conducted as part of Pilot Study evaluations and as part of evaluating custom commercial and industrial programs where adequate data on measure/technology performance does not exist. M&V activities may also be implemented as part of the evaluation of full scale programs if it is felt that additional measure performance data is required.

Wherever practical, the Companies intend to follow the International Performance Measurement and Verification Protocol (IPMVP)[8] in conducting M&V activities for evaluating DSM programs and pilots. FortisBC's review of industry standards, guidelines and protocols indicates that IPMVP is growing in use as a standard resource for guiding the design of M&V activities and provides both a comprehensive and flexible approach. It should be noted that while IPMVP summarizes common industry practices for M&V activities and sets out a range of methodologies that can be followed under ideal study conditions and in absence of budget or timing constraints, it also acknowledges that ideal study conditions and large M&V budgets are seldom available. As such, the Protocol provides guidelines for the evaluator to follow under less than ideal conditions and in the face of budget and timing constraints. The Protocol therefore allows room for judgment by the evaluator under less than ideal evaluation circumstances.

The following M&V principles[9] are embedded in the IPMVP:

Accurate M&V reports should be as accurate as the M&V budget will allow. M&V costs should normally be small relative to the monetary value of the savings being evaluated. M&V expenditures should also be consistent with the financial implications of over- or under-reporting of a project's performance. Accuracy tradeoffs should be accompanied by increased conservativeness in any estimates and judgments.

8 International Performance Measurement and Verification Protocol. Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization. www.evo-world.org. January 2012.

9 These principles have been reproduced from Chapter 3 of the IPMVP (see also the preceding footnote).

Complete The reporting of energy savings should consider all effects of a project. M&V activities should use measurements to quantify the significant effects, while estimating all others.

Conservative Where judgments are made about uncertain quantities, M&V procedures should be designed to under-estimate savings.

Consistent The reporting of a project's energy effectiveness should be consistent between:

- different types of energy efficiency projects;
- different energy management professionals for any one project;
- different periods of time for the same project; and
- energy efficiency projects and new energy supply projects.

'Consistent' does not mean 'identical,' since it is recognized that any empirically derived report involves judgments which may not be made identically by all reporters. By identifying key areas of judgment, IPMVP helps to avoid inconsistencies arising from lack of consideration of important dimensions.

Relevant The determination of savings should measure the performance parameters of concern, or least well known, while other less critical or predictable parameters may be estimated.

Transparent All M&V activities should be clearly and fully disclosed.

3.6 EVALUATION METHODOLOGIES

A range of evaluation methodology types can be utilized to determine the energy savings achieved from the implementation of an efficiency measure. One way to think of this range of methodologies is as of a tool box, with each methodology being a different tool that the evaluator can bring out of the tool box to apply to the evaluation problem. The best tool (or methodology) to use depends on the circumstances of the required evaluation and the available resources. In many cases, more than one methodology will be applied to evaluate the energy savings achieved from an efficiency measure or program of measures. Common evaluation methodologies are summarized as follows:

Billing Analysis

Billing analysis uses customer billing information to assess the effect of a DSM program on customer energy consumption. The analysis typically requires a baseline billing history period in the absence of the EEC measure being installed and one year of billing data following the measure installation. The fundamental assumption is that the only, or major, change in energy consumption over this period has resulted from the EEC measure being evaluated. This approach requires both data cleaning to ensure the quality of the billing data (i.e.: no missed billing reads or estimated bills) and weather adjusting. Market research with the customers involved to is also required to determine if there were changes in occupancy or usage in the premises. When possible, a billing analysis should include both participants and non-participants so that outside influences, such as price changes for fuels, can also be accounted in the analysis. Billing analysis is generally more effective for programs with higher customer savings. Lower savings levels (1-3% for example) can be more difficult to explain using billing analysis due to the potential for other factors to influence energy use patterns.

Metering

Metering involves the installation of energy use meters around the measure being studied to determine specific energy inputs and outputs both prior to and subsequent to the installation of an energy efficiency measure. In the residential sector, metering is primarily used in pilot projects to improve the accuracy of determining the energy impact associated with a DSM measure. Metering can also be used as part of monitoring studies to determine energy usage of appliances over time.

In the commercial and industrial sector metering is commonly used to determine the impact of both custom and pilot programs, where there is insufficient information about the impact of specific measures. Metering analysis can be done on a short-term “spot” basis or on a longer term basis. Long term metering of end-use before and after the installation is preferable to spot metering where economic, and where the participant behavior is not expected to be affected by the measurement.

Simulation Modeling

The effects of efficiency improvements in both residential and commercial buildings can be estimated through simulation of energy use under various scenarios using computer based energy models. In the residential sector, HOT2000 is a commonly used model developed for this purpose, while commercial energy use modeling often requires more complex models such as DOE2. Simulation modeling may be used as part of program design, to obtain initial estimates of energy impact, and/or as part of an initial impact evaluation where billing or metering data is not yet available to refine the modeling estimates.

Engineering Estimates

This method is based on an engineering analysis of the difference in efficiency between the “standard” measure and the installed efficiency measure. It may be based on standard efficiency measurements, such as the difference in EF rating for hot water tanks or the difference in AFUE ratings for furnaces. At a more basic level, it may require analysis of the differences in design of the energy efficient equipment being installed.

Statistically Adjusted Engineering Estimates

This approach utilizes engineering models and statistical approaches to examine the amount and nature of customer end-use loads. The results of simulated end-use loads from engineering methods become inputs into statistical models and are adjusted on the basis of customers' observed loads (statistical data). The resulting end-use loads, called statistically adjusted engineering (SAE) loads, depend on a variety of conditioning variables such as weather and the size and type of the customer's dwelling, or perhaps income and other household characteristics identified as part of the statistical analysis.

Surveys

Survey data is often the basis of both process and impact evaluations. Surveys may take the form of mail, telephone, internet panels, and more recently social media analysis, and may be done with participants and non-participants in any given program. Data collected includes awareness of the program, satisfaction, persistence, usage of the efficiency measure and information to help establish levels of free riders and spillover.

Field Studies and Laboratory Research

This type of analysis can be undertaken are as part of pilot program projects when the utility is conducting a detailed review of a small number of a specific efficiency measures that are "market ready" but not in wide use in the utility's service territory. Typically, the research combines survey data from the customer where the pilot project is being conducted (to understand parameters such as usability and satisfaction with the technology), and metering of baseline and post implementation periods to determine the change in energy use.

Site Visits

Site visits can be used to examine programs across all customer classes to confirm that the target efficiency measure has been successfully installed and is in operation. Site visits can be combined with interviews of homeowners or facility operators to provide additional data valuable to the evaluation process.

Statistical Analysis

Mathematical approaches such as regression analysis and conditional demand analysis are often used in evaluation studies. These approaches can approximate some of the benefits of metering, but through the use of surveys or audits combined with billing histories can include a much larger group of customers at a much lower evaluation cost. Offsetting the cost advantages of this approach, however, are increased uncertainties due to potential changes in energy use unrelated to the efficiency measure being studied.

3.7 OTHER EVALUATION CONSIDERATIONS

Evaluation activities need to consider a number of issues not yet discussed.

Multi – Fuel Impacts

DSM programs may impact the use of electricity, natural gas and other fuels. Often, a program aimed primarily at reducing natural gas consumption may also impact electricity consumption or vice versa. For example a furnace efficiency program that encourages the installation of a variable speed fan might reduce both natural gas and electricity consumption. Natural gas and electricity are the most commonly used energy fuels in BC's built environment; however, the potential exists for the consumption of other fuels, such as propane or heating oil, to similarly be impacted by a DSM program. The potential for such multi-fuel impacts needs to be addressed as part of program evaluation activities.

Persistence of Savings

For natural gas programs, the persistence of energy savings over time is often a function of the life span of the measure or technology. In some cases, however, persistence can be more complex. There may be a need to determine if the equipment or technology being installed will maintain its efficiency rating over time. Also, circumstances may require a shorter (than life span) duration of savings to be assessed such as may occur if the program accelerates the installation of a high efficiency measure that would otherwise require installment at a later date. These complexities must also be addressed as part of the evaluation activities.

Interactive Effects

Impact evaluations should look more broadly than just the energy savings that result from the change in efficiency of the energy conservation measure. Changes in the measure can cause a number of other changes. For example, the evaluation of the residential furnace program (from 2005 to 2007) illustrated that upgrading a furnace has larger impacts than just replacing one technology with another. This evaluation illustrated that the new furnace changed the usage of secondary heat for a share of participants, and also that increases in comfort may result in homeowners selecting lower temperatures in their dwellings. The changes can affect the overall efficiency of energy use, and can also result in changing the balance of all fuel types in use in the building usage including natural gas, electricity and wood.

Attribution of Savings from Joint Programs

FortisBC also undertakes and participates in integrated electricity and natural gas programs, both within the FortisBC utilities and between the FortisBC natural gas utilities and BC Hydro. Attributing for the energy savings and carbon emission reductions that result from such projects among partner organizations needs to be fair, consistent and transparent. FortisBC will work with its partners to develop attribution rules for sharing the credit of energy savings appropriately among program partners and prevent double counting.

Related Studies

In addition to evaluation programs, FEI undertakes a number of studies which are used to support both program development and evaluation. These include:

- Sector End Use Studies conducted periodically to provide a "snapshot" of customers' products and equipment. These studies often include supporting analysis such as "Conditional Demand Analysis" (CDA) components that provide estimates of the amount of natural gas usage by end uses.
- Conservation potential reviews, which are systematic assessments of the current status of energy efficiency in the installed appliance stock in the marketplace and projections of the main end uses where efficiency improvements are possible, along with estimates of potential energy reductions.

3.8 FEEDING EM&V STUDY RESULTS INTO EEC PLANNING

Evaluation and program management staff at FortisBC review the results of evaluation studies and reports to determine if changes to programs are needed. In the case of M&V activities, this review will assist staff in determining if new programs should be developed based on pilot study results or if adjustments need to be made to the data used to determine program or project cost effectiveness. For program design and development, project managers need to consider additional factors such as human, technical and budgetary resources, portfolio priorities and any feedback received from stakeholders. If recommended changes to programs necessitate approval from the BCUC, FortisBC will seek input on those changes from the appropriate Stakeholder Advisory Group.

4. EVALUATION RESOURCES

Effective management of evaluation activities requires both financial and staffing resources.

4.1 *EVALUATION BUDGETS*

Industry practice for budget spending on EM&V activities appears to range between 2 and 10 percent, and average approximately 4 percent of spending on overall energy efficiency and conservation program budgets[10]. This level of spending is in keeping with the principle that evaluation budgets should be a small component of overall programming budgets. That is, an evaluation budget, and therefore evaluation efforts, should not be so extensive that they unnecessarily cause a program to fail a cost-benefit test and thereby prevent the program from being implemented. As such, the Companies will plan EM&V budgets not to exceed 10 percent of overall DSM spending, and will target an annual EM&V budget limit of 3 to 6 percent of the overall EEC portfolio spending.

On a program by program basis, there may be occasions when either higher or lower budgets for individual programs may be appropriate. A new program for which there is very little industry data available and for which energy efficiency performance may have a higher degree of uncertainty, may warrant a higher spending level. Pilot studies that examine the actual performance of a newer technology or measure, for example. In other cases, a program being implemented may benefit from similar programs in other jurisdictions having similar geographic and climate settings may be abundant, evaluation data may be well established and smaller budgets are appropriate.

4.2 *EVALUATION ORGANIZATION*

Wherever possible, the evaluation of programs that span across the Companies' separate utility service territories will be conducted as a single evaluation in order to take advantage of evaluation cost efficiencies and incorporate consistency across service areas. Similarly, evaluations of joint electric and gas DSM programs will be conducted as a single for the partners involved in delivering the program.

Evaluations will be conducted or managed by staff who are independent from the program managers and other staff responsible for designing and implementing DSM programs. Staff responsible for evaluation activities will have separate reporting lines from that of program development and implementation staff wherever practical within the utilities.

4.3 *STAFFING RESOURCES*

The companies recognize that a combination of internal staffing resources and external professional consulting services will be needed to undertake the full range of evaluation

[10] California Evaluation Framework. June 2004. TecMarket Works. p75.

activities that are required for the level of DSM program activity being implemented. The level of internal staff resourcing for evaluation activities will be sufficient to ensure that a base level of evaluation activity can be managed as appropriate for the level of program activity being delivered by the Companies.

External consultants will be retained whenever increased levels of evaluation activity above the base level are such that they cannot be completed by internal staff, and wherever in-house expertise is not available to conduct the necessary studies. Staffing and consultant resources will also be managed within the appropriate budgeting parameters (see Section 4.1).

Sufficient internal staff resources are needed to plan evaluation activities, manage evaluation projects, review third party consultation studies / reports and conduct some evaluation analysis.

- Development of RFPs
- Working with purchasing to obtain quotes from qualified service providers
- Developing selection criteria for the proposals
- Managing the selection criteria
- Managing the evaluation projects
- Maintaining communications with interested parts of the organization (esp. EEC)

Evaluation staff will be involved in the program planning process to determine the major evaluation issues for each program and ensuring that sufficient evaluation resources are available.

Staff Resources for Measurement and Verification Activities:

Internal engineering expertise is required to develop technical measurement and verification process requirements, develop measurement and verification plans, inspect measurement and verification work being done by third parties, be able to conduct measurement and verification activities when necessary. Number of internal staff must be sufficient to manage base level work load, provide consistent project management, and must be managed relative to overall EEC budgeting requirements.

4.4 ROLE OF STAKEHOLDER ADVISORY GROUPS

Advisory Groups made up of key stakeholders external to the Companies have been established by FortisBC to provide insight and feedback on the Companies' portfolios of DSM activities. Advisory Group members are not expected to have a high level of expertise in EM&V and are not expected to provide input on individual evaluation or measurement and verification projects. The Advisory Groups will have access to evaluation report summaries and members may request to see any of the full EM&V reports that are prepared once they are final. Members will also be able to contact FortisBC staff for more detailed discussions/explanations if desired. A list of evaluation activities will also be included in the Companies' Annual Reports for their DSM programs. From time to time, the Companies may review EM&V issues and results with the Advisory Groups for discussion and feedback.

The companies submit evaluation plans through either their Revenue Requirements Application or other filings for approval by the BCUC. Any stakeholder can participate in the review of the evaluation plans through the BCUC's regulatory review process[11].

[11] Visit www.bcuc.com

Attachment 239.1

Zeilstra, Ron

From:	Peter Helland <phelland@midgard-consulting.com>
Sent:	Monday, April 8, 2013 3:17 PM
To:	Zeilstra, Ron
Cc:	'Michael Walsh'
Subject:	Electricity Price Forecast - Proposal
Attachments:	Midgard - FortisBC 2014_33Electricity Forecast Proposal (R02).pdf
Follow Up Flag:	Follow up
Flag Status:	Flagged

Ron,

Please find attached the Midgard proposal for electricity price forecasting.

We look forward to hearing from you and await your response.

Best Regards,

Peter Helland
Midgard Consulting Inc.
Office: 604 298 4997
Cell: 778 996 7747
phelland@midgard-consulting.com
www.midgard-consulting.com

MIDGARD
CONSULTING INC

2014 – 2033 Electricity Price Forecast Proposal for FortisBC

Submitted By: Midgard Consulting Inc.

Date: 8 April 2013

TABLE OF CONTENTS

1 Midgard Introduction

This proposal was prepared at the request of Ron Zeilstra, Resource Development Manager at FortisBC.

Midgard Consulting Incorporated (Midgard) offers engineering and project consulting services to the North American electric utility sector, and specializes in hydroelectric and transmission projects. Midgard's value proposition is founded upon our experience and expertise. Midgard brings together engineering experts with cumulative industry experience of over 100 years, along with a wide network of industry contacts, capabilities, and knowledge. Midgard Consulting personnel are experts in project planning and implementation, with hands on experience in regulatory, finance, permitting, design, construction, and operations.

Midgard Consulting differentiates itself from other consultants in two significant ways:

1) Practical Experience: Midgard's principals have been generation facility planners, developers, owners, and operators. Midgard Consulting thinks and behaves like an owner.

2) Pragmatic Solutions: Midgard Consulting's philosophy is built around a frugal and measured approach to projects and assignments. Our job is to help our clients identify and remove risk from projects in a cost effective manner while progressively graduating projects through a series of milestones and decision points.

Midgard has been involved in a wide variety of energy and electricity forecast exercises, including having performed previous work in this area for FortisBC.

2 Midgard Proposal

Midgard Consulting Inc (Midgard) will provide FortisBC with a 20 year British Columbia electricity price forecast. The price forecast will be for a wholesale product that would be available within FortisBC territory.

The electricity price forecast will consist of three separate price forecasts: a high, a low and a medium (or expected) price curve. The curve will consist of an annual average price (in CAD/MWh) for each of the twenty consecutive years, starting in year 2014. Each of the three curves will be separated into on-peak pricing, off-peak pricing, and average pricing.

2.1 Methodology:

Step 1: The electricity price forecast will be, in part, derived by the forecast wholesale natural gas prices (for the same time period).

Midgard will utilize the base case natural gas price forecast provided to Midgard by FortisBC as the basis for preparing the high, medium and low natural gas curves. [Note: Alternatively, Midgard will take the high, medium and low natural gas price curves directly from FortisBC.] These natural gas curves will be for the Sumas natural gas hub (i.e. Pacific Northwest proxy price).

Step 2: Midgard will construct heat rate forecasts (MMBtu/MWh) in order to transform the regional natural gas price forecasts into regional electricity price forecasts. The regional electricity price forecast will be for Mid-Columbia electricity (power) price (USD/MWh).

The heat rates will be constructed taking into account a number of factors including:

- Regional supply and generation capacity (forecasts)
- Regional load forecasts
- Regional transmission system congestion forecasts
- Carbon tax scenarios, and other miscellaneous price factors

Step 3: Midgard will adjust Mid-Columbia electricity prices to reflect the British Columbia equivalent prices (in CAD/MWh).

The adjustment will consist of applying a transmission related price differential for the price of electricity in the US Mid-Columbia region to the price in British Columbia (e.g. wheeling rate) as well as a foreign exchange conversion rate.

2.2 Deliverables:

1. A table containing three 20 year electricity price curves
   a. Base case (medium) divided into on-peak, off-peak, and average price
   b. High case divided into on-peak, off-peak, and average price
   c. Low case divided into on-peak, off-peak, and average price
2. An accompanying memorandum explaining the methodology followed in the deriving of the various forecast curves, a listing of the assumptions used in the exercise, and a short justification for these assumptions

2.3 Budget and Schedule

		Budget (est.)	Schedule (est.)
Step 1	Natural Gas Curves	[redacted]	1 days
Step 2	Assess and Derive Current Heat Rates	[redacted]	3-5 days
Step 3	Derive Electricity Curves	[redacted]	1 day
Step 4	Memorandum	[redacted]	2 days
Step 5	Revisions to the Draft Report	[redacted]	2 days

Budget: Indicative pric[redacted]

- Work to be performed on a time and materials basis

Schedule: Final working draft to be completed in approximately 2 weeks from issuance of work authorization.

- Midgard assumes that FortisBC will provide to Midgard the initial natural gas curves
- Midgard to issue final report following FortisBC's initial review

Zeilstra, Ron

From: Zeilstra, Ron
Sent: Wednesday, April 10, 2013 1:01 PM
To: Michael Walsh MIR
Subject: Re: Gas Price Forecast used for the electric LTRP and RRA (as it relates to DSM)

Follow Up Flag: Follow up
Flag Status: Flagged

I think this says you can~~d~~ use the expected and create your own high/low

Sent from my iPhone

On 2013-04-10, at 12:52 PM, "Ross, Ken" <Ken.Ross@fortisbc.com> wrote:

> There was no high/low used for the DSM Plan going into the RRA.
>
> For the Resource Plan, yes – as described, we pulled a GLJ forecast from a historic high price environment for use in our high demand forecast and long term EEC outlook and a GLJ forecast from a historic low price environment for the low demand forecast and long term EEC outlook. These were not GLJ high and low forecasts as you would typically see, for example with EIA – GLJ only does one forecast – no high and low iteration.
>
> Also, for the LTRP demand forecast we did not use strictly the commodity forecast, we include other costs in the cost of gas, but I believe it is only the commodity and the carbon price that changes in each case.
>
> Hopefully that helps.
> Ken
>
> ---
>
> **From:** Zeilstra, Ron
> **Sent:** Wednesday, April 10, 2013 12:23 PM
> **To:** Ross, Ken
> **Subject:** Re: Gas Price Forecast used for the electric LTRP and RRA (as it relates to DSM)
>
> Ken - Midgard develops it's own high/low from the expected. Did gas use the GLJ high/low?
>
> Sent from my iPhone
>
> On 2013-04-10, at 11:56 AM, "Ross, Ken" <Ken.Ross@fortisbc.com> wrote:
>
>> Just a heads up that I have been talking to Ron Zeilstra about FBC Electric looking at updating the electric market price forecast they have used in their LTRP and RRA. For this, they are looking at aligning the gas price forecast with the forecast we use. I have advised him that it only makes sense to align the source of the forecast with that used for our LTRP as the vintage of the gas price forecast we used for demand forecasting depends on the scenario. It makes more sense for them to align with the gas price forecast that has been used in determining the avoided cost of gas for our DSM programs in the new DSM Plan. That is the January 2013 GLJ gas price forecast and the current carbon price. Assuming they go ahead and make this change, that means the

gas and electric DSM plans in the RRA will have consistent assumptions about gas and carbon price embedded in them.

Ken Ross
Integrated Resource Planning Manager
FortisBC
ken.ross@fortisbc.com
O: 604-576-7343
C: 604-562-0905

Zeilstra, Ron

From: Zeilstra, Ron
Sent: Friday, April 12, 2013 9:39 AM
To: Michael Walsh MIR
Subject: Fwd: Avoided Cost
Attachments: Avoided Cost Calculation for Ron Zeilstra April 11 2013.xlsx; ATT00001.htm; image001.png; ATT00002.htm

Follow Up Flag: Follow up
Flag Status: Flagged

Here's the gas forecast. We also may want to see if we need consistency on the currency exchange rate

Sent from my iPhone

Begin forwarded message:

> **From:** "Liu, Tony" <Tony.Liu@fortisbc.com>
> **To:** "Zeilstra, Ron" <Ron.Zeilstra@fortisbc.com>
> **Cc:** "Hopkins, Mike" <Mike.Hopkins@fortisbc.com>, "Liu, Tony" <Tony.Liu@fortisbc.com>
> **Subject: Avoided Cost**
>
> Hi Ron,
>
> Please find Sumas gas price for the next 20 years attached. Row 40 on the first two tabs would provide you the prices calculated based on Jan 1st and April 1st, 2013 GLJ Forecast.
>
> Method
>
> (1) Obtain AECO prices from GLJ Forecast - http://www.gljpc.com/pricing-forecast
>
> (2) Apply seasonal factors to get AECO seasonal prices
>
> (3) Apply Station 2–AECO differentials to get Station 2 seasonal prices
>
> (4) Add fuel and transportation costs to get Sumas seasonal prices
>
> (5) Apply normal load seasonal ratios to get Sumas weighted prices
>
> This method is consistent with how we calculate avoided cost for gas DSM purposes. Please let me know if you have any questions and I would be happy to go over it more in detail in person or by phone as required.
>
> Thanks,
>
> Tony Liu
> Market and Price Risk Analyst
> Tony.Liu@FortisBC.com<mailto:Tony.Liu@FortisBC.com>
> Tel: +1 (604) 592-7988 | Fax: +1 (604) 592-7895

FortisBC Energy Inc.
16705 Fraser Highway, Surrey, BC, Canada V4N 0E8
Tel: (604) 576-7000
[Description: cid:image001.png@01CCF529.38807A30]

Zeilstra, Ron

From: Zeilstra, Ron
Sent: Friday, April 12, 2013 11:43 AM
To: Michael Walsh (mwalsh@midgard-consulting.com)
Subject: Gas Price and Exchange rate forecast

Follow Up Flag: Follow up
Flag Status: Flagged

Michael

GLJ January Henry hub forecast was included in one of the tabs in the spreadsheet sent earlier, and is still on their website at

http://www.gljpc.com/commodity-price-library

Exchange rate forecast:

1) Fortis used the Canadian prices in the GLJ Forecast
2) GLJ has a long-term exchange rate forecast in their excel spreadsheet at the above webpage, under the oil tab. It essentially is 1:1 in the long-term
3) We've also included below the current 5 year forwards.

Maybe for the draft curves do a run using your forecast and a run using the GLJ &/or forwards.

Ron Zeilstra
Resource Development Manager
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Phone: 778-578-8093
Cell: 604-209-4357
Email: Ron.Zeilstra@fortisbc.com

From: Liu, Tony
Sent: Friday, April 12, 2013 11:36 AM
To: Zeilstra, Ron
Cc: Hopkins, Mike; Liu, Tony
Subject: RE: Avoided Cost

Hi Ron,
This is the exchange rate we have as of this morning for the next 5 years:

	A	B	C	D	E	F	G	H	I	J	K
1	Forward Price on		12-Apr-2013		US/CD	Spot	6-month	1-Year	2-Year	3-Year	4-Year
2	*(Indication only)*				Exch. Rate	1.0131	1.0173	1.0213	1.0304	1.0403	1.0486

Thanks,

Tony Liu
Market and Price Risk Analyst
Tony.Liu@FortisBC.com
Tel: +1 (604) 592-7988 | Fax: +1 (604) 592-7895
FortisBC Energy Inc.
16705 Fraser Highway, Surrey, BC, Canada V4N 0E8
Tel: (604) 576-7000

From: Liu, Tony
Sent: Friday, April 12, 2013 9:33 AM
To: Zeilstra, Ron
Cc: Hopkins, Mike; Liu, Tony
Subject: Avoided Cost

Hi Ron,

Please find Sumas gas price for the next 20 years attached. **Row 40** on the first two tabs would provide you the prices calculated based on **Jan 1st** and **April 1st, 2013** GLJ Forecast.

Method

(1) Obtain AECO prices from GLJ Forecast - http://www.glipc.com/pricing-forecast
(2) Apply seasonal factors to get AECO seasonal prices
(3) Apply Station 2–AECO differentials to get Station 2 seasonal prices
(4) Add fuel and transportation costs to get Sumas seasonal prices
(5) Apply normal load seasonal ratios to get Sumas weighted prices

This method is consistent with how we calculate avoided cost for gas DSM purposes. Please let me know if you have any questions and I would be happy to go over it more in detail in person or by phone as required.

Thanks,

Tony Liu
Market and Price Risk Analyst
Tony.Liu@FortisBC.com
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FortisBC Energy Inc.
16705 Fraser Highway, Surrey, BC, Canada V4N 0E8
Tel: (604) 576-7000

Zeilstra, Ron

From: Zeilstra, Ron
Sent: Friday, April 12, 2013 1:42 PM
To: Michael Walsh (mwalsh@midgard-consulting.com)
Subject: FW: price forecasts

Follow Up Flag: Follow up
Flag Status: Flagged

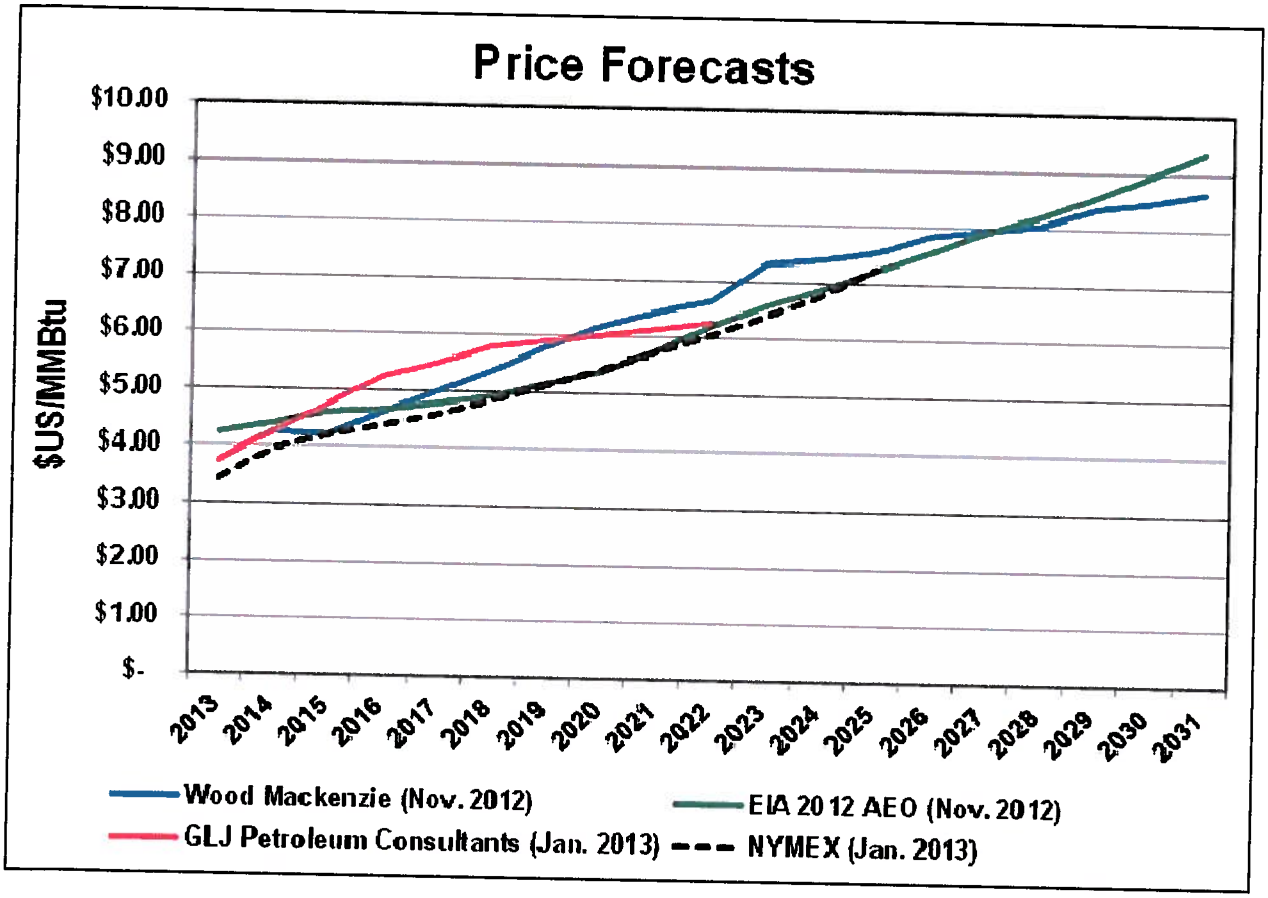
Ron Zeilstra
Resource Development Manager
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Phone: 778-578-8093
Cell: 604-209-4357
Email: Ron.Zeilstra@fortisbc.com

From: Hopkins, Mike
Sent: Tuesday, April 9, 2013 1:55 PM
To: Zeilstra, Ron
Subject: price forecasts

Hi Ron:

Here's a snapshot of some recent gas price forecasts. While the GLJ one only goes out to 2022, it could be extended beyond that at 2% per year. We like to use GLJ and EIA because they are independent sources and the forecasts are accessible for free by everyone. However, keep in mind that some forecasts are only updated by them once a year.



Mike Hopkins
Senior Manager, Commodity and Price Risk
FortisBC
Ph. (604) 592-7842
Fax (604) 592-7895
Cell (604) 341-8586
Email mike.hopkins@fortisbc.com.

Zeilstra, Ron

From: Michael Walsh <mwalsh@midgard-consulting.com>
Sent: Friday, April 12, 2013 4:16 PM
To: Zeilstra, Ron
Subject: 1st Draft - base electricity forecast
Attachments: 2014 Electricity BC Forecast (EIA NG R02).xls; 2014 Electricity BC Forecast (GLJ NG R02).xls

Follow Up Flag: Follow up
Flag Status: Flagged

Hi Ron,

Here are two spreadsheets. These are first drafts of the Electricity Curves.

As discussed, they are drafts and I do want to spend some time going thru them with a fresh mind to be sure we've not made any mistakes, or have mixed up the years, etc.

Both curves use the 1:1 FX that GLJ suggests. I've put an alternative FX in the sheet for easy reference.

I tend to have more faith in the EIA derived prices, largely because the GLJ forecast is so short term relative to the EIA forecast.

I hope this is what you are looking for.

I am available to discuss at your convenience, although I am travelling Monday and Tuesday, so I might be a bit scrambly during business hours.

Enjoy your weekend!

Michael

Zeilstra, Ron

From:	Michael Walsh <mwalsh@midgard-consulting.com>
Sent:	Friday, April 19, 2013 5:08 PM
To:	Zeilstra, Ron
Cc:	Sam Mason
Subject:	Final Midgard BC Electricity Curves
Attachments:	20-Year BC Electricity Forecast (19Apr).xls
Follow Up Flag:	Follow up
Flag Status:	Flagged

Hi Ron,

As discussed, here are the Midgard BC Electricity Curves. There is only a few small changes from what I sent to you last week - namely the years 2041-2043 of the EIA natural gas forecast is slightly higher than what I provided a week ago. Otherwise, I do not believe there are any changes.

I will be away for a few days, but if you have any follow up questions, feel free to email me and/or Sam. Sam is familiar with the files, the methodology and the sourcing of the data.

I will be in touch with you in just over a week, once I am back in Vancouver. Enjoy your weekend.

Kind regards,

Michael Walsh
Principal, Midgard Consulting Inc.
Suite 530, 1130 West Pender St.
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(b) 604-298-4997
(c) 604-828-0509
www.midgard-consulting.com

MIDGARD
CONSULTING INC

Year	Expected[A]	Expected[A]	Heat Rate[B]	Heat Rate[B]	HLH Expected[C]	LLH Expected[C]	All-Hours Expected[C]	Expected
	Henry Hub	Henry Hub	HLH	LLH	MID C	MID C	MID C	GHG Adder[D]
	2011 $$	2013 $$	n/a	n/a	2013 $$	2013 $$	2013 $$	2013 $$
	USD/MMBtu	USD/MMBtu	MMBtu/MWh	MMBtu/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh
2014	$3.122	$3.265	7.9	6.1	$25.79	$19.91	$23.15	$4.00
2015	$3.118	$3.261	7.9	6.1	$25.76	$19.89	$23.17	$4.67
2016	$3.566	$3.729	7.9	6.1	$29.46	$22.74	$26.44	$5.34
2017	$3.697	$3.866	7.9	6.1	$30.54	$23.58	$27.41	$5.74
2018	$3.958	$4.139	7.9	6.1	$32.69	$25.25	$29.34	$6.80
2019	$4.047	$4.231	7.9	6.1	$33.43	$25.81	$30.00	$6.94
2020	$4.134	$4.323	7.9	6.1	$34.15	$26.37	$30.65	$7.60
2021	$4.258	$4.453	7.9	6.1	$35.18	$27.16	$31.57	$3.60
2022	$4.477	$4.681	7.9	6.1	$36.98	$28.55	$33.19	$3.60
2023	$4.674	$4.888	7.9	6.1	$38.61	$29.81	$34.65	$3.87
2024	$4.787	$5.006	7.9	6.1	$39.54	$30.53	$35.49	$3.87
2025	$4.871	$5.093	7.9	6.1	$40.23	$31.07	$36.11	$4.67
2026	$5.020	$5.249	7.9	6.1	$41.47	$32.02	$37.22	$5.20
2027	$5.094	$5.327	7.9	6.1	$42.08	$32.49	$37.77	$5.47
2028	$5.219	$5.458	7.9	6.1	$43.12	$33.29	$38.69	$5.74
2029	$5.299	$5.541	7.9	6.1	$43.77	$33.80	$39.28	$6.40
2030	$5.398	$5.644	7.9	6.1	$44.59	$34.43	$40.02	$6.80
2031	$5.535	$5.788	7.9	6.1	$45.72	$35.31	$41.03	$7.07
2032	$5.631	$5.888	7.9	6.1	$46.51	$35.91	$41.74	$7.42
2033	$5.772	$6.036	7.9	6.1	$47.68	$36.82	$42.79	$7.81
2034	$6.036	$6.312	7.9	6.1	$49.86	$38.50	$44.75	$8.19
2035	$6.322	$6.611	7.9	6.1	$52.22	$40.32	$46.87	$8.58
2036	$6.694	$7.000	7.9	6.1	$55.30	$42.70	$49.63	$8.96
2037	$7.039	$7.360	7.9	6.1	$58.15	$44.90	$52.19	$9.35
2038	$7.421	$7.760	7.9	6.1	$61.30	$47.34	$55.02	$9.73
2039	$7.589	$7.936	7.9	6.1	$62.69	$48.41	$56.26	$10.12
2040	$7.829	$8.186	7.9	6.1	$64.67	$49.94	$58.04	$10.50
2041	$8.013	$8.379	7.9	6.1	$66.20	$51.11	$59.41	$10.88
2042	$8.203	$8.577	7.9	6.1	$67.76	$52.32	$60.81	$11.27
2043	$8.396	$8.780	7.9	6.1	$69.36	$53.56	$62.25	$11.65

Year	HLH Expected w GHG	LLH Expected w GHG	All Hours Expected w GHG	BPA Tx Wheeling[E]	Losses[F]	Exchange[G]	Expected Fortis BC	Expected Forth BC
	MID-C w GHG+	MID C w GHG+	MID C w GHG+	"Congestion+" (USD/MWh)	Losses (USD/MWh)	FX	"FBC" Electricity	"FBC" Electricity
	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	n/a	2013 $$	Current
	USD/MWh	USD/MWh	USD/MWh	1.00%	1.90%	CAD/USD	CAD/MWh	CAD/MWh
2014	$29.79	$23.92	$27.15	$1.917	$0.552	$1.00	$29.62	$30.24
2015	$30.43	$24.56	$27.79	$1.936	$0.565	$1.000	$30.29	$31.57
2016	$34.79	$28.08	$31.77	$1.956	$0.641	$1.000	$34.37	$36.58
2017	$36.28	$29.32	$33.15	$1.975	$0.667	$1.000	$35.79	$38.89
2018	$39.50	$32.05	$36.15	$1.995	$0.725	$1.000	$38.86	$43.12
2019	$40.36	$32.75	$36.94	$2.015	$0.740	$1.000	$39.69	$44.96
2020	$41.75	$33.97	$38.25	$2.035	$0.765	$1.000	$41.05	$47.48
2021	$38.78	$30.76	$35.17	$2.055	$0.707	$1.000	$37.93	$44.79
2022	$40.58	$32.16	$36.79	$2.076	$0.738	$1.000	$39.61	$47.75
2023	$42.48	$33.68	$38.52	$2.097	$0.772	$1.000	$41.39	$50.95
2024	$43.41	$34.40	$39.36	$2.118	$0.788	$1.000	$42.26	$53.12
2025	$44.90	$35.74	$40.78	$2.139	$0.815	$1.000	$43.73	$56.12
2026	$46.67	$37.22	$42.42	$2.160	$0.847	$1.000	$45.43	$59.52
2027	$47.55	$37.96	$43.24	$2.182	$0.863	$1.000	$46.28	$61.91
2028	$48.85	$39.03	$44.43	$2.204	$0.886	$1.000	$47.52	$64.90
2029	$50.18	$40.20	$45.69	$2.226	$0.910	$1.000	$48.82	$68.08
2030	$51.39	$41.23	$46.82	$2.248	$0.932	$1.000	$50.00	$71.19
2031	$52.79	$42.38	$48.10	$2.270	$0.957	$1.000	$51.33	$74.62
2032	$53.94	$43.34	$49.17	$2.293	$0.978	$1.000	$52.44	$77.83
2033	$55.49	$44.63	$50.60	$2.316	$1.005	$1.000	$53.92	$81.71
2034	$58.06	$46.70	$52.94	$2.339	$1.050	$1.000	$56.33	$87.16
2035	$60.80	$48.90	$55.45	$2.362	$1.098	$1.000	$58.91	$93.05
2036	$64.26	$51.66	$58.59	$2.386	$1.159	$1.000	$62.13	$100.21
2037	$67.49	$54.24	$61.53	$2.410	$1.215	$1.000	$65.16	$107.29
2038	$71.03	$57.07	$64.75	$2.434	$1.276	$1.000	$68.46	$115.10
2039	$72.81	$58.52	$66.38	$2.458	$1.308	$1.000	$70.14	$120.41
2040	$75.17	$60.44	$68.54	$2.483	$1.349	$1.000	$72.37	$126.84
2041	$77.08	$62.00	$70.29	$2.508	$1.383	$1.000	$74.18	$132.75
2042	$79.03	$63.59	$72.08	$2.533	$1.418	$1.000	$76.03	$138.91
2043	$81.01	$65.21	$73.90	$2.558	$1.453	$1.000	$77.91	$145.34

Year	HISTORIC CPI[Z]
	January
	1982/84 - 100
2001	175.1
2002	177.1
2003	181.7
2004	185.2
2005	190.7
2006	198.3
2007	202.416
2008	211.080
2009	211.143
2010	216.687
2011	220.223
2012	226.665
2013	230.280

Year	Inflator	Alternative FX
	Current starting with 2013$	
	2.10%	
2014	102.1%	$1.02
2015	104.2%	$1.032
2016	106.4%	$1.044
2017	108.7%	$1.056
2018	111.0%	$1.068
2019	113.3%	$1.081
2020	115.7%	$1.093
2021	118.1%	$1.105
2022	120.6%	$1.117
2023	123.1%	$1.129
2024	125.7%	$1.141
2025	128.3%	$1.153
2026	131.0%	$1.165
2027	133.8%	$1.177
2028	136.6%	$1.189
2029	139.4%	$1.202
2030	142.4%	$1.214
2031	145.4%	$1.226
2032	148.4%	$1.238
2033	151.5%	$1.25
2034	154.7%	$1.25
2035	158.0%	$1.25
2036	161.3%	$1.25
2037	164.7%	$1.25
2038	168.1%	$1.25
2039	171.7%	$1.25
2040	175.3%	$1.25
2041	178.9%	$1.25
2042	182.7%	$1.25
2043	186.5%	$1.25

Notes & Sources

A) AEO 2013 NG (Henry Hub) Spot Price Forecast
B) Heat rates based upon the historic (~11 year) average ratio between Henry Hub spot prices and Mid-C day-ahead prices, data source: Intercontenental Exchange (www.theice.co
C) HLH=55% of all hours (4800 of 8760 h/yr), LLH = 45% of all hour
D) http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/lrp_tac_mtg2_meeting0.pdf, slide
E) BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summar
F) BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation
G) http://www.gljo.com/commodity-price-forecasts (31JAN2013 version
Z) Historic CPI data from the US Bureau of Labor: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.tx

Year	Expected[A] Henry Hub 2013 $$ USD/MMBtu	Heat Rate[B] HLH n/a MMBtu/MWh	Heat Rate[B] LLH n/a MMBtu/MWh	HLH Expected[C] MID C 2013 $$ USD/MWh	LLH Expected[C] MID C 2013 $$ USD/MWh	All-Hours Expected[C] MID C 2013 $$ USD/MWh	Expected GHG Adder[D] 2013 $$ USD/MWh
2014	$4.17	7.9	6.1	$32.94	$25.44	$29.57	$4.00
2015	$4.57	7.9	6.1	$36.10	$27.88	$32.40	$4.67
2016	$4.95	7.9	6.1	$39.11	$30.20	$35.10	$5.34
2017	$5.08	7.9	6.1	$40.13	$30.99	$36.02	$5.74
2018	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80
2019	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.94
2020	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.60
2021	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60
2022	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60
2023	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87
2024	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87
2025	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$4.67
2026	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.20
2027	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.47
2028	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.74
2029	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.40
2030	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80
2031	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.07
2032	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.42
2033	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.81
2034	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.19
2035	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.58
2036	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.96
2037	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.35
2038	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.73
2039	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.12
2040	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.50
2041	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.88
2042	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.27
2043	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.65

Year	HLH Expected w GHG MID-C w GHG+ 2013 $$ USD/MWh	LLH Expected w GHG MID-C w GHG+ 2013 $$ USD/MWh	All-Hours Expected w GHG MID-C w GHG+ 2013 $$ USD/MWh	BPA Tx Wheeling[E] "Congestion+" (USD/MWh) 2013 $$ 1.00%	Losses[F] Losses (USD/MWh) 2013 $$ 1.90%	Exchange[G] FX n/a CAD/USD	Expected Fortis BC "FBC" Electricity 2013 $$ CAD/MWh	Expected Fortis BC "FBC" Electricity Current CAD/MWh
2014	$36.94	$29.44	$33.57	$1.917	$0.674	$1.00	$36.16	$36.92
2015	$40.77	$32.55	$37.07	$1.936	$0.741	$1.000	$39.75	$41.43
2016	$44.44	$35.53	$40.43	$1.956	$0.805	$1.000	$43.19	$45.97
2017	$45.87	$36.72	$41.75	$1.975	$0.831	$1.000	$44.56	$48.42
2018	$48.28	$38.83	$44.03	$1.995	$0.874	$1.000	$46.89	$52.03
2019	$48.41	$38.96	$44.16	$2.015	$0.877	$1.000	$47.05	$53.30
2020	$49.08	$39.63	$44.83	$2.035	$0.890	$1.000	$47.75	$55.23
2021	$45.08	$35.63	$40.82	$2.055	$0.815	$1.000	$43.69	$51.60
2022	$45.08	$35.63	$40.82	$2.076	$0.815	$1.000	$43.72	$52.71
2023	$45.34	$35.89	$41.09	$2.097	$0.821	$1.000	$44.01	$54.17
2024	$45.34	$35.89	$41.09	$2.118	$0.821	$1.000	$44.03	$55.34
2025	$46.14	$36.69	$41.89	$2.139	$0.837	$1.000	$44.87	$57.57
2026	$46.68	$37.23	$42.42	$2.160	$0.847	$1.000	$45.43	$59.52
2027	$46.94	$37.49	$42.69	$2.182	$0.853	$1.000	$45.73	$61.17
2028	$47.21	$37.76	$42.96	$2.204	$0.858	$1.000	$46.02	$62.85
2029	$47.88	$38.43	$43.63	$2.226	$0.871	$1.000	$46.72	$65.15
2030	$48.28	$38.83	$44.03	$2.248	$0.879	$1.000	$47.15	$67.13
2031	$48.55	$39.10	$44.29	$2.270	$0.885	$1.000	$47.45	$68.97
2032	$48.90	$39.45	$44.65	$2.293	$0.892	$1.000	$47.83	$70.99
2033	$49.28	$39.83	$45.03	$2.316	$0.900	$1.000	$48.25	$73.11
2034	$49.67	$40.22	$45.42	$2.339	$0.907	$1.000	$48.66	$75.29
2035	$50.05	$40.60	$45.80	$2.362	$0.915	$1.000	$49.08	$77.53
2036	$50.44	$40.99	$46.18	$2.386	$0.923	$1.000	$49.49	$79.82
2037	$50.82	$41.37	$46.57	$2.410	$0.931	$1.000	$49.91	$82.19
2038	$51.21	$41.76	$46.95	$2.434	$0.938	$1.000	$50.33	$84.61
2039	$51.59	$42.14	$47.34	$2.458	$0.946	$1.000	$50.74	$87.10
2040	$51.97	$42.52	$47.72	$2.483	$0.954	$1.000	$51.16	$89.66
2041	$52.36	$42.91	$48.11	$2.508	$0.962	$1.000	$51.58	$92.29
2042	$52.74	$43.29	$48.49	$2.533	$0.969	$1.000	$51.99	$94.99
2043	$53.13	$43.68	$48.88	$2.558	$0.977	$1.000	$52.41	$97.77

Year	Inflator Current starting with 2013$ 2.10%	Alternative FX
2014	102.1%	$1.02
2015	104.2%	$1.032
2016	106.4%	$1.044
2017	108.7%	$1.056
2018	111.0%	$1.068
2019	113.3%	$1.081
2020	115.7%	$1.093
2021	118.1%	$1.105
2022	120.6%	$1.117
2023	123.1%	$1.129
2024	125.7%	$1.141
2025	128.3%	$1.153
2026	131.0%	$1.165
2027	133.8%	$1.177
2028	136.6%	$1.189
2029	139.4%	$1.202
2030	142.4%	$1.214
2031	145.4%	$1.226
2032	148.4%	$1.238
2033	151.5%	$1.25
2034	154.7%	$1.25
2035	158.0%	$1.25
2036	161.3%	$1.25
2037	164.7%	$1.25
2038	168.1%	$1.25
2039	171.7%	$1.25
2040	175.3%	$1.25
2041	178.9%	$1.25
2042	182.7%	$1.25
2043	186.5%	$1.25

Notes & Sources

A) http://www.glja.com/commodity-price-forecasts (31JAN2013 version)
B) Heat rates based upon the historic (~11 year) average ratio between Henry Hub spot prices and Mid-C day-ahead prices; data source: Intercontenental Exchange (www.theice.com)
C) HLH=55% of all hours (4800 of 8760 h/yr), LLH = 45% of all hours
D) http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/irp_tac_mtg2_meeting0.pdf, slide 87
E) BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary
F) BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"
G) http://www.glja.com/commodity-price-forecasts (31JAN2013 version)

Zeilstra, Ron

From: Michael Walsh <mwalsh@midgard-consulting.com>
Sent: Thursday, May 2, 2013 1:33 PM
To: Zeilstra, Ron
Cc: Chris Oakley
Subject: Memo detailing the 2014-2043 BC Electricity Curves Forecasting Exercise
Attachments: Memo 2014_2043 Electricity Px Forecast (May2013).pdf

Follow Up Flag: Follow up
Flag Status: Flagged

Hi Ron,

Attached is the final draft of the memo for the 2014-2043 Electricity Forecasting exercise.
Once you have the opportunity to review, please let me know if you have any question, comments or concerns.

Kind regards,

Michael Walsh

MIDGARD

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MEMORANDUM

To: Ron Zeilstra, FortisBC

From: Midgard Consulting

Date: May 2, 2013

Subject: Derivation of the British Columbia Electricity Price Forecast 2014 to 2043

The memorandum outlines the methodology to generate two different estimates of the price of electricity within the British Columbia market, for the years 2014 through 2043.

Overview

Although there are transparent and liquid electricity markets in jurisdictions that neighbour British Columbia (namely the Alberta Electricity Market, and the much larger and more accessible Mid-Columbia Electricity Market), there is no transparent or liquid electricity market in British Columbia.

Consequently, future electricity prices in British Columbia can be forecast based upon a forecast price for electricity originating from the Mid-Columbia (or Mid-C) trading hub and delivered to the British Columbian border.

Given that there is limited visibility and liquidity for Mid-C electricity prices in the long term (i.e. more than 5 years from today), the 30 year forecast (2014 through 2043) was based upon the expected cost of electricity in future years, rather than an easily traded futures based price. Furthermore, given the prominent role that natural gas prices play in determining the marginal cost of generating electricity in most WECC jurisdictions, the expected cost of electricity in the future is believed to be closely associated with the expected cost of natural gas during those same periods.

Step-by-Step Methodology – Based on GLJ Baseline Natural Gas Prices

Step 1a – Obtain Natural Gas Baseline Annual Price (GLJ baseline natural gas prices)

- Extract the natural gas forecast price (Henry Hub, real dollars) from the website of GLJ Petroleum Consultants (http://www.glja.com/commodity-price-library; 31 JAN 2013 version).
- This price is in real U$2013/MMBtu. The GLJ price forecast runs from 2014 through 2023. Since, the price from 2018 through 2023 is constant (at $5.25/MMBtu), this constant price (of $5.25/MMBtu) is continued for the years 2024 through 2043.
- The resulting Henry Hub natural gas price forecast is called the GLJ Henry Hub price.

Step 2a – Derive Heat Rates (MMBtu to MWh energy conversion ratio)

- Historic pricing data from the Intercontinental Exchange (ICE)[1] is used to derive the historic heat rate (ratio of cost of electricity over cost of natural gas) between Henry Hub natural gas and Mid-C day-ahead electricity prices. The data examined ran from April 2013 (the latest available data) and going back to 2002. This heat rate data is used to calculate representative heat rates that can be applied to on-peak and off-peak hours going forward for each month of the year.
- All data is actual prices (U$/MMBtu for the natural gas prices and U$/MWh for the electricity prices).
- The heat rates witnessed over the past decade experienced periods of extremes from year to year, and clear seasonal patterns (e.g. low heat rates during the freshet period), however the overall annual averages display solid correlations between the natural gas and electricity prices, and the resulting heat rates are a good predictor of expected future heat rates.
- Midgard examined both the correlations between Henry Hub natural gas prices and Stanfield prices (i.e. local Pacific Northwest ('PNW') natural gas hub). Although the Stanfield - Mid-C correlations were slightly higher than the Henry Hub ones, the Henry Hub - Mid-C correlations were nevertheless very high. Midgard employed the Henry Hub natural gas price forecast as the basis of calculating the long term Mid-C electricity price because the Henry Hub curve is far more readily available and less subject to non-energy factors (e.g. transport restrictions) than the alternative natural gas indexes that were considered for this exercise.

Step 3a – Generate GLJ Mid-C Electricity Forecast

- The GLJ Henry Hub price forecast (from Step 1a) is multiplied by the heat rates calculated in Step 2a in order to derive a GLJ Mid-Columbia electricity price forecast.
    - The Mid-C electricity price forecast calculations were made for both on-peak and off-peak pricing.
    - Midgard also examined the Sunday 1x16 pricing, however that data set was shorter than the on-peak and off-peak data sets, and produced results that were more volatile than the other two data sets. Consequently, Midgard opted to use only the on-peak and off-peak derived heat rates to calculate the Mid-C price forecast for electricity (treating the Sunday 1x16 as an off-peak period).

Step 4a – Translate Mid-C Price Forecast to BC Price Forecast

- The Midgard BC Electricity price forecast represents the cost that FortisBC would face if they were to purchase electricity at Mid-C and wheel the power to the Canada-US border; Midgard has assumed that FortisBC pricing would not be required to be wheeled through the BC Hydro grid, and hence attract additional wheeling and system losses costs that would further raise the electricity price.
- The forecast is not meant to represent the cost of importing power, but rather an average price of electricity within the British Colombia context.

[1] www.theice.com

- The following factors are then applied to translate the Mid-C price forecast to the BC context (i.e. to the Canadian border):
    1. Account for the price difference between high and low load hours
    2. Include a GHG (or carbon) adder to the price of electricity
    3. Account for cost of transmitting the electricity from Mid-C to the Canadian border, including BPA wheeling rates[2], and transmission line losses[3].
    4. $USD:$CDN exchange rate.

- Midgard assumed that the high load hours equates to 16 hours per day for 6 days per week for 52 weeks per year minus 12 holidays, or 4800 hours per year

    - HLH=55% of all hours (4800 of 8760 h/yr), LLH = 45% of all hours

    - The ratios (i.e. weightings) are used in the deriving of the all-hours electricity price

- The expected impacts that greenhouse gas ('GHG') regulations will have upon electricity prices in the British Columbia context were determined as follows.

    - GHG calculation is based upon work performed by Black & Veatch for the BC Hydro for use within their current (2012/2013) Integrated Resource Plan. The information is publicly available and sufficiently detailed to enable Midgard to formulate a suitable opinion on the applicability of the work, particularly to its intended cause of estimating the potential impact to PNW prices given the recent regulatory proposals surrounding the regulation/pricing of emissions regimes within North America in general, and that will impact BC in particular.

    - The report contains several scenarios forecasts, including a low GHG price adder. Midgard feels that the low GHG price adder scenario is the most plausible scenario, and therefore used those prices within this exercise.

- The wheeling rate for 2014 is calculated as $1.917 USD/MWh. The transmission losses used are 1.90% of the expected Mid-C price (including the wheeling charges).

    - Midgard assumed that the costs of wheeling power would increase by 1% per annum in real terms, which is a proxy for the additional costs of congestion as well as infrastructure additions within the region.

- The foreign exchange assumption used to transform $USD/MWH into $CAD/MWH is 1:1; this assumption is derived from the GLJ January 2013 forecast (http://www.glja.com/commodity-price-forecasts; 31JAN2013 version).
- The Midgard BC Electricity forecast is presented both in real 2013 $CAD/MWh as well as nominal $CAD/MWh.

---

[2] BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary

[3] BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"

- Apply a 2.1% inflation rate to convert real dollar values ($2013CAD) to nominal dollars ($CAD).

Step-by-Step Methodology – Based on EIA Baseline Natural Gas Prices

Step 1b – Obtain Natural Gas Baseline Annual Price (EIA baseline natural gas prices)

- Extract the natural gas forecast price (Henry Hub, real dollar) from the EIA's Annual Energy Outlook (AEO) 2013; http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm
- From the AEO data, extract the Henry Hub price forecast (http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm, table 13, row: Henry Hub Spot Price)
- The AEO data runs from 2014 through 2040, consequently for the years 2041 to 2043, Midgard extrapolated the natural gas prices based upon the average annual price increase over the 2011-2040 time period, which is 2.04%.
- This price is in real U$2011/MMBtu. The base year for the Midgard BC Electricity Forecasting exercise is 2013. Consequently, the Henry Hub price forecast was transformed into U$2013 using historic CPI data from the US Bureau of Labor (ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt). The CPI inflation ratio used is 1:1.046.
- The resulting Henry Hub natural gas price forecast is called the EIA Henry Hub price.

Step 2b – Derive Heat Rates (MMBtu to MWh energy conversion ratio)

Same as Step 2a for the GLJ methodology.

Step 3b – Generate EIA Mid-C Electricity Forecast

Same as Step 3a from the GLJ methodology except that the EIA Henry Hub natural gas forecast (from Step 1b) is used as the input data source (and not the GLJ Henry Hub natural gas forecast from Step 1a).

Step 4b – EIA Mid-C to BC Electricity (EIA baseline natural gas prices)

Same as Step 4b for the GLJ forecast except that the EIA Mid-C price forecast (from Step 3b) is used as the input data source (and not the GLJ Mid-C price forecast from Step 3a).

Table 1 – Natural Gas to Electricity Transformation of Units: Steps

STEP	TRANSITION	START	END	DETAILS
1a	Natural Gas baseline (GLJ)	USD/MMBtu in $2013	USD/MMBtu in $2013	Original source data: 1) GLJ[4]

[4] http://www.glja.com/commodity-price-forecasts (31JAN2013 version)

1b	Natural Gas baseline (EIA): change to base year of constant USD	USD/MMBtu in $2011	USD/MMBtu in $2013	Original source data: 2) EIA[5]
2a & 2b	Natural Gas => Electricity	Heat Rate	Heat Rate	Develop market heat rates for different months of the year
3a & 3b	Natural Gas => Electricity	USD/MMBtu in $2013	USD/MWh in $2013	Apply heat rate to convert MMBtu into MWh
4a & 4b	Electricity price adders	USD/MWh in $2013	CAD/MWh in $2013	Apply anticipated increase to annual price resulting from a) greenhouse gas regulatory impacts, b) wheeling costs and line losses from Mid-C to BC border, and c) Foreign Exchange conversion
	Real CAD => Nominal CAD	$2013 CAD /MWh	$CAD/MWh in Nominal dollars	Assumes an annual inflation rate of 2.10%

[5] http://www.eia.gov/forecasts/aeo/er/tables_ref.cfm

Zeilstra, Ron

From: Zeilstra, Ron
Sent: Tuesday, June 11, 2013 7:20 AM
To: Michael Walsh
Cc: Egolf, Dan (FortisBC Electric)
Subject: Re: BC Market Forecast

Follow Up Flag: Follow up
Flag Status: Flagged

Hi Michael

Just a write-up justifying the methodology, and just the GLJ forecast. I don't think we are looking for anything else, Dan?

I'm tied up in a regulatory workshop this morning, and on a flight to Castlegar this afternoon, but I'll give you a call when I get a chance.

Sent from my iPhone

On 2013-06-10, at 10:27 PM, "Michael Walsh" <mwalsh@midgard-consulting.com> wrote:

> Hi Ron,
>
> For the write up, are you looking for an explanation of the methodology (e.g. similar to the memo sent on May 2nd) or something that is more a justification of the curves?
>
> Also, is it for both (electricity curves) or the one based upon GLJ Baseline Natural Gas derived curve?
>
> (If there is a specific IR that is a good sample to try and answer, that may help answer my questions.)
>
> I could have a memo by the end of the week - sooner if it is urgent.
>
> My gut tells me that it will be 1/2 day to 1 day of work (but divided into multiple sessions - so at least 2 days), but let me confirm the above questions first before I firm up an estimate.
>
> If it's easier to discuss by phone, please let me know when a good time to talk would be.
>
> Thanks and regards,
>
> Michael W.
>
>
>
> On 2013-06-10, at 9:21 PM, Zeilstra, Ron wrote:
>
>> Michael. It looks like we may need a write-up of the forecast as we may get IRs asking us to provide it. Not looking for anything too elaborate, just a short write-up providing and explaining the forecast which we can handout. What do you think it would cost and what's the turn-around time.
>>
>> Sent from my iPhone
>>

Zeilstra, Ron

From: Michael Walsh <mwalsh@midgard-consulting.com>
Sent: Saturday, June 15, 2013 1:30 PM
To: Zeilstra, Ron; Egolf, Dan (FortisBC Electric)
Cc: Peter Helland
Subject: Re: BC Market Forecast
Attachments: Memo 2014 to '43 Electricity Px Forecast - step by step (GLJ R01).docx; 30-Year BC Electricity Forecast (GLJ June 2013).xls

Importance: High

Ron and Dan,

Attached is the 30 year natural gas to electricity curve, along with a memo explaining the transformation steps. I have sent you the word document in order to facilitate cutting and pasting (for IRs, say).

These are modified versions of the earlier work that Midgard provided you.
The information is strictly to do with the GLJ natural gas forecast based curve. The memo was been simplified - it avoids explanations of decisions that could invite second guessing (if they were provided as a response to an information request).

I hope that this is what you had in mind. If you wish do discuss further, or are looking for a different approach or formatting to the memo, do not hesitate to contact me.

In particular, please let me know if you want the additional background analysis (e.g. heat rate data analysis) or documents (e.g. Black and Vetch/BC Hydro GHG source information).

Respectfully,

Michael Walsh
604-828-0509

----- Original Message -----
From: "Zeilstra, Ron" <Ron.Zeilstra@fortisbc.com>
To: "Michael Walsh MIR" <mwalsh@midgard-consulting.com>
Cc: "Egolf, Dan (FortisBC Electric)" <dan.egolf@fortisbc.com>
Sent: Monday, June 10, 2013 9:21 PM
Subject: BC Market Forecast

Michael. It looks like we may need a write-up of the forecast as we may get IRs asking us to provide it. Not looking for anything too elaborate, just a short write-up providing and explaining the forecast which we can handout. What do you think it would cost and what's the turn-around time.

Sent from my iPhone

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MEMORANDUM

To: Ron Zeilstra, FortisBC

From: Midgard Consulting

Date: 15 June 2013

Subject: Derivation of the British Columbia Electricity Price Forecast 2014 to 2043

The memorandum outlines the methodology to generate the price of electricity within the British Columbia market, for the years 2014 through 2043.

Overview

Although there are transparent and liquid electricity markets in jurisdictions that neighbour British Columbia (namely the Alberta Electricity Market, and the much larger Mid-Columbia Electricity Market), there is no transparent or liquid electricity market in British Columbia.

Nonetheless, future electricity prices in British Columbia can be forecast based upon a forecast price for electricity originating from the Mid-Columbia (or Mid-C) trading hub and delivered to the British Columbian border.

Given that there is limited visibility and liquidity for Mid-C electricity prices in the long term (i.e. more than 5 years from today), the 30 year forecast (2014 through 2043) was based upon the forecast cost of natural gas in future years. Given the prominent role that natural gas prices play in determining the marginal cost of generating electricity in most WECC jurisdictions, the expected cost of electricity in the future is forecast to be closely associated with the expected cost of natural gas during those same time periods.

Step-by-Step Methodology – Based on GLJ Baseline Natural Gas Prices

<u>Step 1a – Obtain Natural Gas Baseline Annual Price (GLJ baseline natural gas prices) – Column B</u>

- The natural gas forecast price (Henry Hub, real dollars) from the website of GLJ Petroleum Consultants (http://www.glja.com/commodity-price-library; JAN 2013 version) are used as the starting point. This natural gas price forecast is consistent with the one used in other recent FortisBC regulatory filings.
- The natural gas price is quoted in real U$2013/MMBtu. The GLJ price forecast runs from 2014 through 2023. The price average from 2018 through 2023 (which is constant at $5.25/MMBtu) is continued for the years 2024 through 2043 (i.e. $5.25/MMBtu).
- The resulting Henry Hub natural gas price forecast is titled the Henry Hub within the spreadsheet *(Column B)*.

Step 2a – Derive Heat Rates (MMBtu to MWh energy conversion ratio) – Column E and F

- Historic pricing data from the Intercontinental Exchange (ICE)[1] is used to derive the historic heat rate (ratio of cost of electricity over cost of natural gas) between Henry Hub natural gas prices and Mid-C day-ahead electricity prices. The data examined ran from April 2013 (the latest available data at the time of the analysis) back to 2002. This heat rate data is used to calculate representative heat rates that can be applied to high load hours (or HLH, also known as on-peak hours) and low load hours (or LLH, also known as off-peak hours) going into the future *(Column E and F)*.
- All data are quoted in actual prices (U$/MMBtu for the natural gas prices and U$/MWh for the electricity prices).
- The heat rates witnessed over the past decade experienced periods of extremes from year to year, and clear seasonal patterns (e.g. low heat rates during the freshet period), however the overall annual averages display solid correlations between the respective natural gas and electricity prices. The resulting average heat rates are a good predictor of expected future heat rates.
- Midgard examined the correlations between Mid-C prices and Henry Hub natural gas prices. The Henry Hub - Mid-C correlations are very high. Midgard employed the Henry Hub natural gas price forecast as the basis of calculating the long term Mid-C electricity price because the Henry Hub curve is the predominant natural gas price benchmark in North America. Historic data and price forecasts for Henry Hub natural gas are readily available.

Step 3a – Generate Mid-C Electricity Forecast – Column G, H and I

- The Henry Hub price forecast (from Step 1a) is multiplied by the heat rates calculated in Step 2a in order to derive a Mid-Columbia electricity price forecast.
- The Mid-C electricity price forecast calculations were made for both HLH and LLH *(Column G and H)*. [2]
- The Mid-C "All-Hours" electricity price is a weighted average of the HLH and LLH prices *(Column I)*.
    - Midgard assumed that the high load hours equate to 16 hours per day for 6 days per week for 52 weeks per year minus 12 holidays, or 4800 hours per year
        - HLH=55% of all hours (4800 of 8760 h/yr), the remaining are LLH = 45% of all hours
        - The ratios (i.e. weightings) are used in the deriving of the all-hours electricity price

Step 4a – Translate Mid-C Price Forecast to BC Price Forecast – Column Q

- The Midgard BC Electricity price forecast shadows the cost that FortisBC would face if they were to purchase electricity at Mid-C and wheel the power to the Canada-US border; Midgard has assumed that FortisBC pricing would not be required to be wheeled through the BC Hydro grid, and hence attract additional wheeling and system losses costs that would further raise the electricity price.

---

[1] www.theice.com

[2] Midgard also examined the Sunday 1x16 pricing, however that data set was smaller than the on-peak and off-peak data sets, and produced results that were more volatile (i.e. statistically less reliable) than the results of the other two data sets. Consequently, Midgard opted to use only the on-peak and off-peak derived heat rates to calculate the Mid-C price forecast for electricity (treating the Sunday 1x16 as an off-peak period).

- The forecast is not meant to represent the cost of importing power, but rather a proxy for the average price of electricity within the British Colombian context.
- The following factors are applied to translate the Mid-C price forecast to the BC context (i.e. to the Canadian border):
    1. Account for the price difference between high and low load hours *(Column I)*
    2. Include a GHG (or carbon) adder to the price of electricity *(Column J)*
    3. Account for cost of transmitting the electricity from Mid-C to the Canadian border, including Bonneville Power Administration (BPA) wheeling rates[3] *(Column N)*, and transmission line losses[4] *(Column O)*.
    4. $USD:$CDN exchange rate *(Column P)*.
- The resulting Expected FortisBC price is in real 2013 Canadian dollars per megawatt hour *(Column Q)*.

Miscellaneous Cost Factors

- The expected impacts that greenhouse gas (GHG) regulations will have upon electricity prices in the British Columbian context were determined as follows.
    - GHG calculation is based upon work performed by Black & Veatch for the BC Hydro for use within their current (2012/2013) Integrated Resource Plan. The information is publicly available.
    - The report contains several scenario forecasts, including a low GHG price adder. Midgard feels that the low GHG price adder scenario is the most plausible scenario, and therefore used those prices within this exercise *(Column J)*.
- The BPA wheeling rate for 2014 is calculated as $1.917 USD/MWh. The transmission losses used are 1.90% of the expected Mid-C price (including the wheeling charges) *(Column N)*.
    - Midgard assumed that the costs of wheeling power would increase by 1% per annum in real terms, which is a proxy for the additional costs of congestion as well as infrastructure additions within the region.
- The foreign exchange assumption used to transform $USD/MWh into $CAD/MWh is 1:1; this assumption is derived from the GLJ January 2013 forecast (http://www.glja.com/commodity-price-forecasts; JAN2013 version) *(Column P)*.
- The Midgard BC Electricity forecast is presented both in real 2013 $CAD/MWh as well as nominal $CAD/MWh.
    - Apply a 2.1% annual inflation rate *(Column U)* to convert real dollar values ($2013CAD) to nominal dollars ($CAD) *(Column R)*.

[3] BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary

[4] BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"

Year	Expected[A]	Heat Rate[B]		HLH Expected[C]	LLH Expected[C]	All-Hours Expected[C]	Expected	HLH Expected w GHG	LLH Expected w GHG	All-Hours Expected w GHG	BPA Tx Wheeling[E]	Losses[F]	Exchange[G]	Expected Fortis BC	Expected Fortis BC
	Henry Hub	HLH	LLH	MID-C	MID-C	MID-C	GHG Adder[D]	MID-C w GHG+	MID-C w GHG+	MID-C w GHG+	"Congestion+" (USD/MWh)	Losses (USD/MWh)	FX	"FBC" Electricity	"FBC" Electricity
	2013 $$	n/a	n/a	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	n/a	2013 $$	Current
	USD/MMBtu	MMBtu/MWh	MMBtu/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	1.00%	1.90%	CAD/USD	CAD/MWh	CAD/MWh
2014	$4.17	7.9	6.1	$32.94	$25.44	$29.57	$4.00	$36.94	$29.44	$33.57	$1.917	$0.674	$1.00	$36.16	$36.92
2015	$4.57	7.9	6.1	$36.10	$27.88	$32.40	$4.67	$40.77	$32.55	$37.07	$1.936	$0.741	$1.000	$39.75	$41.43
2016	$4.95	7.9	6.1	$39.11	$30.20	$35.10	$5.34	$44.44	$35.53	$40.43	$1.956	$0.805	$1.000	$43.19	$45.97
2017	$5.08	7.9	6.1	$40.13	$30.99	$36.02	$5.74	$45.87	$36.72	$41.75	$1.975	$0.831	$1.000	$44.56	$48.42
2018	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80	$48.28	$38.83	$44.03	$1.995	$0.874	$1.000	$46.89	$52.03
2019	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.94	$48.41	$38.96	$44.16	$2.015	$0.877	$1.000	$47.05	$53.30
2020	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.60	$49.08	$39.63	$44.83	$2.035	$0.890	$1.000	$47.75	$55.23
2021	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60	$45.08	$35.63	$40.82	$2.055	$0.815	$1.000	$43.69	$51.60
2022	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60	$45.08	$35.63	$40.82	$2.076	$0.815	$1.000	$43.72	$52.71
2023	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87	$45.34	$35.89	$41.09	$2.097	$0.821	$1.000	$44.01	$54.17
2024	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87	$45.34	$35.89	$41.09	$2.118	$0.821	$1.000	$44.03	$55.34
2025	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$4.67	$46.14	$36.69	$41.89	$2.139	$0.837	$1.000	$44.87	$57.57
2026	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.20	$46.68	$37.23	$42.42	$2.160	$0.847	$1.000	$45.43	$59.52
2027	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.47	$46.94	$37.49	$42.69	$2.182	$0.853	$1.000	$45.73	$61.17
2028	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.74	$47.21	$37.76	$42.96	$2.204	$0.858	$1.000	$46.02	$62.85
2029	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.40	$47.88	$38.43	$43.63	$2.226	$0.871	$1.000	$46.72	$65.15
2030	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80	$48.28	$38.83	$44.03	$2.248	$0.879	$1.000	$47.15	$67.13
2031	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.07	$48.55	$39.10	$44.29	$2.270	$0.885	$1.000	$47.45	$68.97
2032	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.42	$48.90	$39.45	$44.65	$2.293	$0.892	$1.000	$47.83	$70.99
2033	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.81	$49.28	$39.83	$45.03	$2.316	$0.900	$1.000	$48.25	$73.11
2034	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.19	$49.67	$40.22	$45.42	$2.339	$0.907	$1.000	$48.66	$75.29
2035	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.58	$50.05	$40.60	$45.80	$2.362	$0.915	$1.000	$49.08	$77.53
2036	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.96	$50.44	$40.99	$46.18	$2.386	$0.923	$1.000	$49.49	$79.82
2037	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.35	$50.82	$41.37	$46.57	$2.410	$0.931	$1.000	$49.91	$82.19
2038	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.73	$51.21	$41.76	$46.95	$2.434	$0.938	$1.000	$50.33	$84.61
2039	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.12	$51.59	$42.14	$47.34	$2.458	$0.946	$1.000	$50.74	$87.10
2040	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.50	$51.97	$42.52	$47.72	$2.483	$0.954	$1.000	$51.16	$89.66
2041	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.88	$52.36	$42.91	$48.11	$2.508	$0.962	$1.000	$51.58	$92.29
2042	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.27	$52.74	$43.29	$48.49	$2.533	$0.969	$1.000	$51.99	$94.99
2043	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.65	$53.13	$43.68	$48.88	$2.558	$0.977	$1.000	$52.41	$97.77

Year	Inflator	Alternative FX
	Current starting with 2013$	
	2.10%	
2014	102.1%	$1.02
2015	104.2%	$1.032
2016	106.4%	$1.044
2017	108.7%	$1.056
2018	111.0%	$1.068
2019	113.3%	$1.081
2020	115.7%	$1.093
2021	118.1%	$1.105
2022	120.6%	$1.117
2023	123.1%	$1.129
2024	125.7%	$1.141
2025	128.3%	$1.153
2026	131.0%	$1.165
2027	133.8%	$1.177
2028	136.6%	$1.189
2029	139.4%	$1.202
2030	142.4%	$1.214
2031	145.4%	$1.226
2032	148.4%	$1.238
2033	151.5%	$1.25
2034	154.7%	$1.25
2035	158.0%	$1.25
2036	161.3%	$1.25
2037	164.7%	$1.25
2038	168.1%	$1.25
2039	171.7%	$1.25
2040	175.3%	$1.25
2041	178.9%	$1.25
2042	182.7%	$1.25
2043	186.5%	$1.25

Notes & Sources

A) http://www.glja.com/commodity-price-forecasts (01JAN2013 version)
B) Heat rates based upon the historic (~11 year) average ratio between Henry Hub spot prices and Mid-C day-ahead prices; data source: Intercontenental Exchange (www.theice.com)
C) HLH=55% of all hours (4800 of 8760 h/yr), LLH = 45% of all hours
D) http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/irp_tac_mtg2_meeting0.pdf, slide 87
E) BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary
F) BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"
G) http://www.glja.com/commodity-price-forecasts (01JAN2013 version)

Attachment 245.2

210.0 Reference: Energy Efficiency and Conservation

Exhibit B-1, Appendix K-1, pp. 20-21

Recognition of Spillover Effects in Net-to-Gross Ratio

" …it is important to attempt to capture additional energy savings from spillover…."

[redacted]

210.2 Is the FEU aware of other natural gas utilities where spillover effects are included in net to gross (NTG) calculations? Please provide the list of natural gas companies and the period of time such spillover effects were incorporated in the NTG analysis.

Response:

There are some natural gas utilities where spillover effects are included in NTG calculations. National Grid, for example, in Masschusetts, incorporates spillover in its NTG calculations[74]. BC Hydro also incorporates spillover effects in NTG calculations.[75] Florida, Illinois, Massachusetts,

[74] `Source: http://www.ma-eeac.org/docs/MA%20TRM_2011%20PLAN%20VERSION.PDF, pp 16 - 20

[75] `Source: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/directive_66_summary_report.Par.0001.File.2008_04_11%20DSMMES%20RPT.pdf

New York and Oregon include spillover effects, while California, Wisconsin and Connecticut do in some cases.[76]

The Companies were not able to determine the period of time such spillover effects have been incorporated into the NTG analysis in each jurisdiction, however on a practical level, this would be on a program-by-program basis, depending on the nature of the program.

[redacted]

[76] `Source: http://eetd.lbl.gov/ea/EMS/reports/lbnl-3277e.pdf, p 19.

Attachment 248.2

FortisBC

Conservation and Demand Potential Review
Final Report

September 19, 2013

Prepared by:

EES Consulting

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EES Consulting

September 19, 2013

Mr. Keith Veerman, P. Eng.
Manager, PowerSense Programs
FortisBC Inc.
Suite 100, 1975 Springfield Road
Kelowna, BC, V1Y 7V7 Canada

SUBJECT: FortisBC Conservation and Demand Potential Review

Dear Mr. Veerman:

Please find attached the Final FortisBC Conservation and Demand Resource Potential Review report prepared by EES Consulting. This report provides the background and results of the CDPR developed over the past several months. The results of the three scenarios are presented.

Thank you for your assistance in developing the baseline data, and your input and review throughout the process.

Please contact me if you have questions and/or comments about the report.

Best Regards,

Kevin L. Smit

Kevin Smit
Manager Energy Efficiency/DSM

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Contents

Introduction

Objectives

The objective of this report is to describe the results of the FortisBC 2013 Conservation and Demand Potential Review (CDPR). This assessment updates the previous (2010) CDPR and provides estimates of energy and peak demand savings by sector for the period of 2014 - 2033. The assessment considered a wide range of conservation and demand resources that are reliable, available, and cost-effective. In addition, some emerging technologies, fuel switching, small scale generation, and behavioural measures were considered.

The conservation measures are based on sources such as the BC Hydro, Ontario Power Authority, Conservation Potential Assessment, Regional Technical Forum, and the Northwest Power and Conservation Council. The results provide estimates of energy savings that will assist FortisBC in their future resource and program planning.

Background

FortisBC provides service to 129,000 direct customers in the province of British Columbia as well as 34,000 indirect customers through wholesale supply to municipalities such as Summerland, Penticton, Grand Forks, and Nelson. Direct residential customers make up nearly 44 percent of energy sales. Wholesale customers make up another 20 percent of energy (all wholesale classes), with the remaining 36 percent related to direct commercial, industrial and other retail classes. Energy sales for FortisBC are roughly 3.5 million MWh per year, with a winter peak demand of about 710 MW. The summer peak for the system is roughly 524 MW.

FortisBC owns generation from four hydro units collectively referred to as the Kootenay River Plants. Output from these plants is governed by a water coordination contract with BC Hydro, and other parties on the Kootenay River which predefines the amount of power that can be used at various times. Peak capacity for the Kootenay River Plants is 223.5 MW. Plant output accounts for approximately 45 percent of energy requirements and 30 percent of the sum of the monthly capacity requirements. The remainder of FortisBC's power supply needs is met with power supply purchases, including a wholesale contract purchase of up to 200 MW per hour from BC Hydro. While FortisBC resources and contracts provide the majority of energy required by the utility, the system was traditionally constrained with respect to capacity. The advent of the Waneta Expansion project in 2015 will close the capacity resource gap.

The utility has made significant investments into its electrical infrastructure. Since 2005, FortisBC has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure. Much of the investment was made to accommodate ongoing capacity constraints on the FortisBC transmission and distribution systems. In addition, customer peak electrical usage has been growing quicker in the summer than in the winter due in part to increased air conditioning load.

Regulatory and Planning

From a government policy perspective, changes to the Utilities Commission Act (UCA), and the introduction of the DSM Regulation as revised in December 2011, have also necessitated consideration in FortisBC's planning process.

The *2007 BC Energy Plan*, and the subsequent *2010 Clean Energy Act (CEA),* played a significant role in FortisBC's evaluation of potential sources for additional power, providing public policy guidance on directions that BC would like to take in making these types of decisions. Some of the specific public policy measures outlined include:

- BC Hydro to acquire 50 percent, updated to 66% in the CEA, of incremental resource needs through conservation by 2020;
- Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia; and
- Encourage utilities to pursue cost effective and competitive demand side management opportunities.

The Ministry of Energy & Mines report, *Energy Efficient Buildings Strategy: More Action, Less Energy* goes a step further by setting new targets specifically for buildings that support the goals of the BC Energy Plan. These targets include:

- Reduce average energy demand per home by 20 per cent by 2020
- Low income retrofit incentives
- SolarBC project
- Net zero energy homes project
- Reduce energy demand in commercial buildings by nine per cent per square meter by 2020
- Complete energy conservation plans for all B.C. communities

The UCA requires the Company to pursue demand-side resources prior to supply-side options. While FortisBC realizes that demand-side resources alone may not be able to close the capacity gap, the utility and its customers could benefit from these resources by reducing the need for added capacity, securing low-risk resources at relatively low costs, and realizing environmental benefits such as reduced or avoided greenhouse gas emissions.

FortisBC contracted EES Consulting, Inc. (EESC) to develop a Conservation and Demand Response Potential Review (CDPR). The initial 2010 CDPR study evaluated the conservation and demand response savings potential for the period 2011 through 2030. It was filed in June 2011 to support the 2012 Long Term DSM Plan, along with the 2012 Resource Plan, as part of the FBC 2012 Integrated System Plan omnibus filing. The ISP and its components were approved by the Regulator in August 2012.

This 2013 CDPR updates the 2010 CDPR with the latest load forecasts, consumption data, and conservation achievements since the 2010 study.

Report Organization

This report is organized as follows:

- Methodology for Conservation Potential Estimation
- Historic FortisBC Conservation Achievement
- End-Use Load Forecast
- Residential Energy Efficiency Savings Potential
- Commercial Energy Efficiency Savings Potential
- Industrial Energy Efficiency Savings Potential
- Irrigated Agriculture Conservation Potential
- Behaviour Measures
- Combined CDM Potential Summary
- Scenarios

Within each potential section, service territory data is defined, conservation measures identified, and estimated potential is summarized.

In addition to the main report, the appendices contain detailed information regarding potential estimates as well as supplementary information.

Methodology

This study is a comprehensive analysis that focuses mainly on a bottom-up approach where energy efficiency measures are applied to specific end-uses, such as number of refrigerators, and assigned a specific kWh/year savings. This approach differs from "top-down" approaches where, in many cases, a percentage savings is assumed for each end-use. This section describes how conservation potential is estimated in this study as well as the specific considerations, vocabulary, and reasoning behind the methodologies described. First, the types of conservation potential are defined followed by the methodology for estimating those types of potential.

Types of Potential

In developing this potential study, several different types or levels of efficiency potential are identified: technical, economic, and achievable. Technical potential is the theoretical maximum efficiency in the service territory. Economic potential is a subset of the technical potential that has been screened for cost effectiveness through various benefit-cost tests. Beyond cost effectiveness, there are physical barriers, market conditions, and other economic constraints that reduce the total potential savings from an energy efficient device. When these factors are applied, the result is called the achievable potential.

- *Technical* – Amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures. It represents the theoretical maximum amount of energy efficiency if these constraints are not considered.
- *Economic* – Amount of potential that passes an economic cost/benefit test; in British Columbia the total resource cost test (TRC) is used. This generally means that the present value of the benefits exceeds the present value of the measure costs over its lifetime. The TRC costs include the incremental cost of the measure regardless of who pays (utility or customer). In British Columbia the Ministry of Energy and Mines ("Ministry") has mandated that the cost effectiveness of measures be calculated either at the individual level, in a bundle with other measures, or at a portfolio level.
- *Achievable* – Amount of potential that can be achieved through a given set of conditions. Achievable potential takes into account many of the realistic barriers to adopting energy efficiency measures. These barriers include the willingness of consumers to adopt a measure, the non-measure costs, and the physical limitations of ramping up a program over time. The level of achievable potential can increase or decrease depending on the given incentive level of the measure.
- *Program Achievable* – Amount of potential that can be achieved through programs. The program achievable excludes potential that is achieved through future code changes.

Data Requirements

The data required for estimating conservation potential falls into three categories: measure data, customer characteristic, and utility data. Figure 1 illustrates specific data included in each of these categories.

Figure 1
Overview of Potential Assessment Data Requirements

Energy Efficiency Measure Data
- kWh, kW savings, load shapes
- Costs - incremental, O&M, replacement
- Energy and non-energy benefits/costs
- Measure Life

Customer Characteristic Data
- Residential: single family, multifamily, manufactured
- Commercial: Floor area by building segment, population, employment
- Industrial: consumption by sub-sector
- Building characteristics: heating fuel, vintage, basement type, HVAC types
- Appliance saturation: refrigerators, lighting
- Commercial building square footage; total and by segment
- Current measure penetration rate

Utility Data
- Load forecast
- Avoided cost
- Discount rates
- Line losses
- Past energy efficiency program achievements

Energy Efficiency Measure Data

The characterization of efficiency measures includes measure savings (kWh), demand savings (kW), measure costs ($), and measure life (years). Other features such as measure load shape, operation and maintenance costs, and non-energy benefits are also important for measure definition. Next, the end-use conservation measures data is another piece central to conservation potential modeling. Three primary sources were referenced for conservation measure data that apply to characteristics in FortisBC's service territory: the 2007 BC Hydro Conservation Potential Review, the Northwest Council's Regional Technical Forum, the Northwest Power and Conservation Council's Sixth Power Plan, and Ontario Power Authority measure databases. Annual savings for heating, cooling, and weatherization measures are adjusted to reflect the FortisBC climate zones.

The measure data from some or all of the resources listed above include adjustments from raw savings data for several factors. The effects of space heating interaction, for example, are included for all lighting and appliance measures where appropriate. For example, if a house is retrofitted with efficient lighting, the heat that was originally provided by the inefficient lighting will have to be made up by the heating system. This energy is netted out of the savings.

Customer Characteristic Data

In order to characterize the baseline, customer characteristics data is defined in this study using end-use surveys completed by FortisBC. An end-use survey provides detailed housing and commercial building data requirements. FortisBC periodically completes end-use surveys for their residential and commercial customers. The results are used to guide which conservation measures are applicable as well as the corresponding saturation levels of those measures.

The building, appliance, and equipment data is obtained from the FortisBC customer surveys. Using FortisBC survey data, the end-use model forecasts saturations and building segmentation data over the planning period. The end-use model allows for the estimation of conservation potential over a period of time, rather than a snap-shot in time, as survey results show. Therefore, the estimation of growth rates and saturation levels over the time period becomes an integral piece to conservation potential.

Utility Data

The third category is utility data which includes current and forecasted loads, growth rates, avoided cost information, and line losses. FortisBC provided a load forecast by sector with average annual growth of 1.2 percent (gross load) over the period 2013 through 2018. The average growth rate was used to extend the forecast through the planning period. Line losses are assumed at 8 percent over the period. The load forecast provided includes historic conservation trends through utility programs and code and standard changes.

The inflation rate assumed is 2 percent annually with a utility nominal discount rate of 8 percent (i.e., real discount rate = 6 percent).

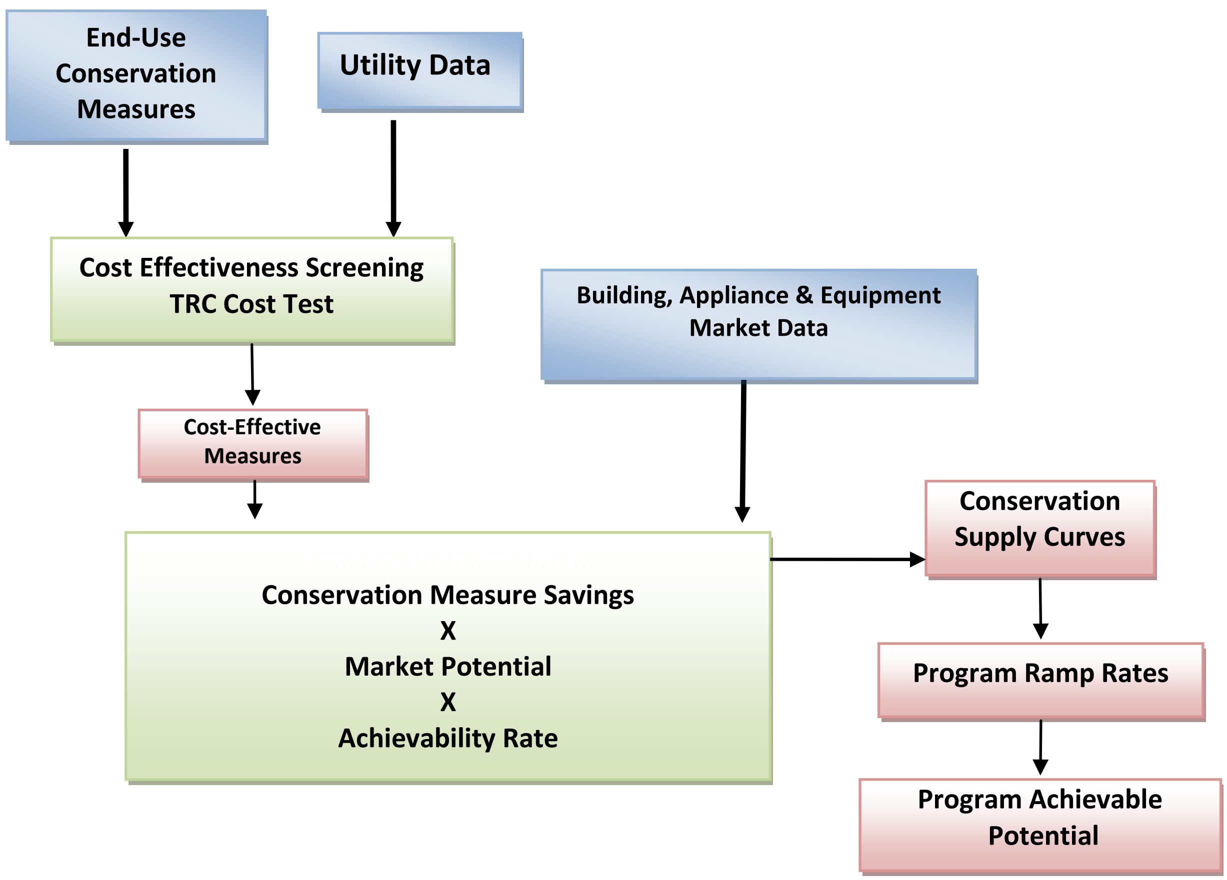
Energy Benefits

The avoided cost of electricity is the dollar value per MWh, of the conserved electricity, and accounts for the primary benefit value in cost effectiveness tests. In addition, avoided costs for transmission and distribution as well as peak summer and winter demand is also valued ($/kW). These energy benefits are often based on the cost of a generating resource, a forecast of market prices or an integrated resource planning process. For this study long-term avoided costs are used to value firm energy, inclusive of capacity. A transmission and distribution factor of $35.60/kW-yr is also included. A range of avoided costs for energy measures is used in the CDPR. These avoided costs are discussed in the “Scenarios” section of this report.

Basic Modeling Methodology

There are two general analytical approaches to estimating conservation potential: a bottom-up approach and a top-down approach. The bottom-up approach is the primary method used for this assessment and is illustrated by Figure 2. The key factor is the number of kWh saved annually from the installation of an individual energy efficient measure. The savings from each measure is multiplied by the total number of measures that could be installed over the life of the program. Savings from each individual measure is then aggregated to produce the total potential.

Figure 2
Conservation Potential Assessment Process



Estimating Technical Potential

The technical potential is the sum of all measure savings and possible applications of the measure across the service territory. Estimating the technical potential begins with determining a value for the energy efficiency measure savings. Then, the number of "applicable units" must be estimated. "Applicable units" refers to the number of units that could technically be installed in a service territory. This includes accounting for units that may already be in place. A sample formula for calculating technical potential for a residential measure is shown below:

Measure Savings = (Per Unit Savings) x (# of households) x (Applicability) x (1- Saturation)

The “Applicability” value is highly dependent on the measure and the housing stock. For example, a heat pump measure may only be applicable to single family homes with electric space heating equipment. The “Saturation” value identifies the number of measures that have already been installed.

In addition, technical potential considers the interaction and stacking effects of measures. For example, if a home installs insulation and a high efficiency heat pump, the total savings in the home is less than if each measure were installed individually (i.e., interaction). In addition, the measure-by-measure savings depend on which measure is installed first (i.e., stacking). For example, if a type of efficient equipment has three levels of efficiency, the savings value of the lowest efficiency measure is the difference between its consumption and the existing equipment. The next level of efficiency assumes the difference between the first level and the second, and so on.

Total technical potential is often significantly more than the amount of economic and achievable potential. The difference between technical potential and achievable and/or economic potential is due to the number of measures in the technical potential that are not cost-effective, and the applicability or total amount of savings of those non-cost effective measures.

Estimating Economic Potential

Energy efficiency potential assessments estimate the amount of energy savings potential that is available and cost-effective. To find cost-effectiveness potential, energy efficiency measures must pass economic screening. In British Columbia, economic potential is defined using a total resource cost (TRC) test to screen measures for cost effectiveness. A total resource cost perspective considers all costs and benefits for each energy efficiency measure regardless of to whom they occur. Costs and benefits include: measure cost, O&M cost over the life of the measure, disposal costs, program administration costs, distribution and transmission benefits, energy savings benefits, and non-energy savings benefits. Appendix A describes the TRC test as it applies in British Columbia in more detail.

Another common cost-effectiveness test is the utility cost test (UCT) (also known as the program administrator cost test). This test considers only those costs and benefits that accrue to the utility. The drawback of this method is that it does not ensure that public resources are allocated in the most efficient manner. Energy efficiency measures with significant non-energy benefits, but smaller energy benefits may not pass the screening. Also, this test does not include all the costs of the measure but only those that accrue to the utility. FortisBC requested that UCT results be presented for each measure. In addition, participant cost tests (from the participant perspective) as well as rate-payer impact tests are also included. Appendix B describes these various cost-effectiveness tests in more detail.

Estimating Achievable Potential

Achievability criteria can be applied either to technical potential or to economic potential. There are several methods for accounting for achievability, in the US Pacific Northwest, the NWPCC applies achievability criteria prior to the economic cost-effectiveness tests. Specifically, the NWPCC uses an 85% achievability factor for all measures and has published a white paper describing the basis for using this value[1]. This value indicates that over the course of a 20-year potential study, 85% of all technical potential can be achieved, regardless of how it is achieved.

There are many different types of achievability factors and many ways to apply them. In addition, the achievability can be evaluated through different scenarios (e.g., high, medium, low). Scenarios can be based on the level of incentives offered or other program design factors.

Model Output - Supply Curves

Each type of potential can be summarized by a supply curve where savings potential (MWh) is graphed against the levelized cost ($/MWh). Measure costs are standardized (levelized) allowing for the comparison of measures with different lives. The supply curve facilitates comparison or demand-side resources to supply-side resources and is often used in conjunction with Integrated Resource Plans (IRPs).

Levelized Cost

The levelized cost of the measure is the discounted present value cost of the measure annualized over its life divided by the annual energy savings. The equation below illustrates how the levelized cost is calculated.

$$Levelized\ Cost = \frac{r}{1 - \frac{1}{(1+r)^{measure\ life}}} \times (measure\ \mathrm{cost} + program\ admin\ costs)$$

Where *r* is the interest rate.

---

[1] "Achievable Savings: A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions." August 2007. http://www.nwcouncil.org/library/2007/2007-13.htm.

Dividing the equation above by the annual savings (MWh) produces levelized cost in terms of dollars per MWh. This levelized cost calculation is the same as BC Hydro's Cost of Conserved Energy (CCE).

Program Achievable Potential

The last step to estimating reasonably attainable conservation potential over the time period is to assign ramp rates to each measure. Ramp rates might be individual for each measure, or one type of ramping might apply to several similar measures. How quickly savings from a particular measure is ramped up over the period depends on several factors:

- Availability of technology (measures);
- Industry capacity (to install measures);
- Program readiness (e.g., for emerging technologies, the potential is ramped up more slowly over time to allow for market acceptance);
- Whether the measure is implemented before or at the end of building or unit life; and
- Changes in codes or standards.

Ramp rates are applied to achievable potential; the result is program achievable potential, or the amount of potential a utility could reasonably expect to obtain over the time period given best current knowledge.

Historic Conservation Achievement

Historic conservation achievements are examined to adjust the 2014 end-use consumption estimates as well as the baseline characteristics for potential estimation. FortisBC has been active in helping their customers become more energy efficiency through their PowerSense program since 1989. Previous programs have included residential, commercial, and industrial measures. Figure 3 illustrates historic conservation efforts from 1990 through 2012.

Figure 3
Historical Energy Efficiency Achievements

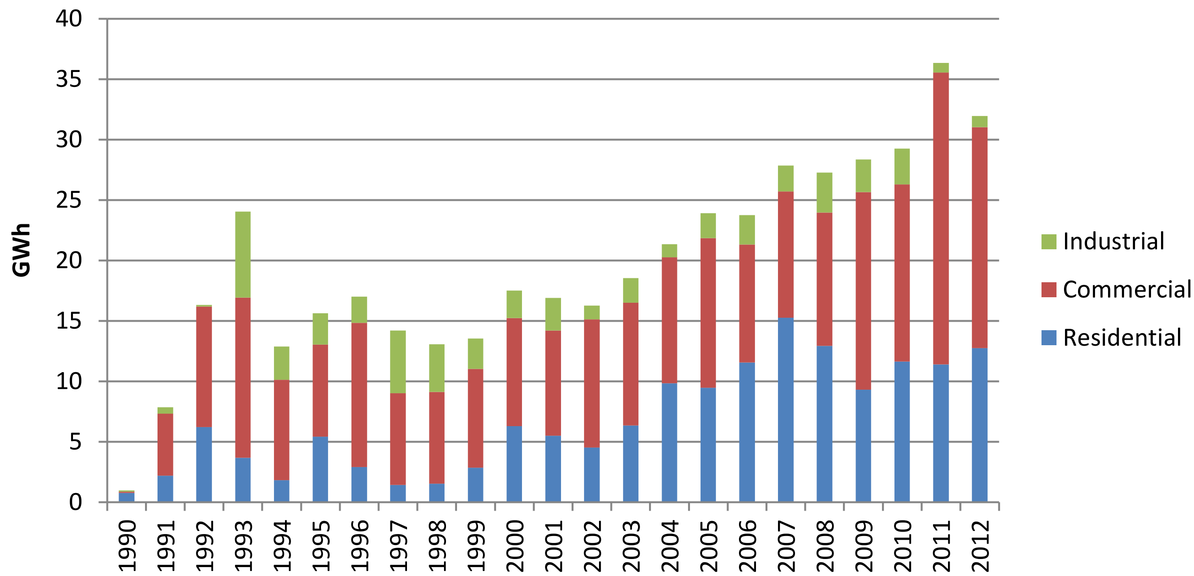
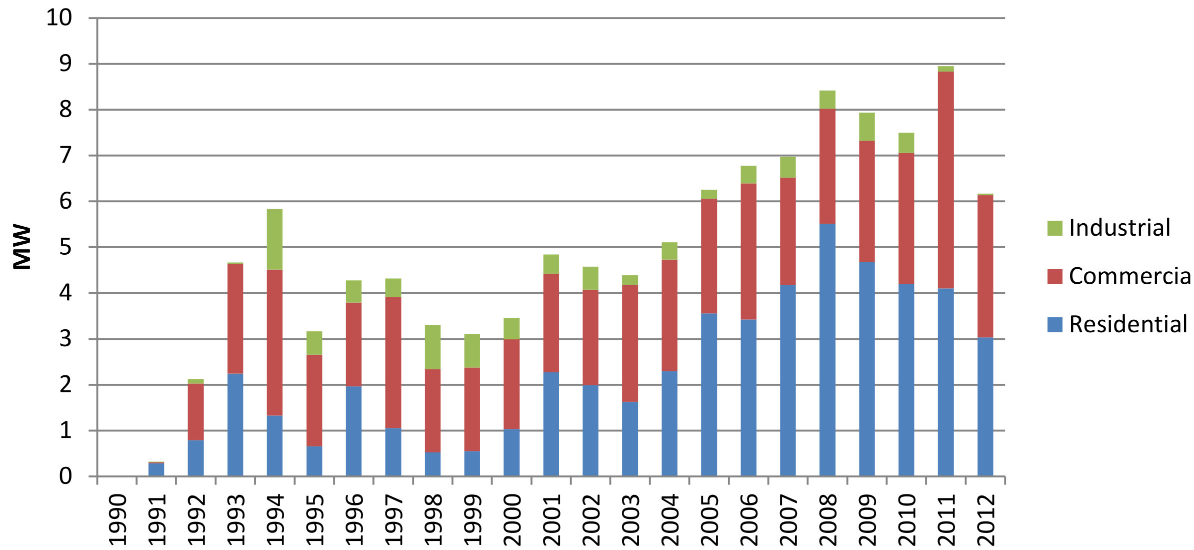


Figure 4 shows the associated demand savings for the energy savings in Figure 3.

Figure 4
Peak Demand Savings



The programs currently being utilized by FortisBC to acquire these savings are briefly described in the following sections. The eligible measures, programs and incentive offers shown are subject to change in current or future DSM filings with the Regulator.

Residential Incentives

LiveSmart BC - Provincial Program

To take advantage of FortisBC's energy efficiency incentives, some programs require that homeowners work through a government-run program called LiveSmart BC. This program coordinates utility, provincial, and federal promotions and has funding to operate through March 31, 2014. Since its launch in 2008, LiveSmart BC has invested $110 million saving an average of 15 to 28 percent on participant home energy bills. To take advantage of LiveSmart BC, homeowners must order an energy evaluation for their home, which is subsidized by the provincial government. Some PowerSense rebates can be accessed through LiveSmart BC. These programs are identified in the descriptions below.

PowerSense

Residential electric energy efficiency programs include the following:

- **New Home Program (NHP)** – offers homeowners and builders rebates on energy efficient design, lighting, and technologies such as heat pumps for new construction projects.

- **EnerGuide Energy Evaluation** – Rebate up to $500 per single family home or duplex
- **Performance Path (EnerGuide Rating)**
    - EG 80 - $1,500 per detached home or duplex
    - EG 85 or higher - $3,000 per detached home or duplex
- **Prescriptive Path (pick list of qualifying measures)**
    - **ICF or SIP Construction** - $500 rebate per detached dwelling.
    - **Air Source Heat Pump** – Rebates $200 per ton. Ductless heat pump $300 per ton. Packaged terminal heat pump rebates are $100 per ton.
    - **Ground source heat pump** – Energy Star, rebate $500 per ton.
- **Lighting & Appliances (in addition to either path):**
    - **Lighting Rebates** – CFL rebates of 50% up to $2.50 per bulb, CFL fixture 50% up to $10, LED hardwired 50% up to $50, LED bulb 10W or greater 50% or up to $30, LED bulb less than 10W 50% up to $15.
    - **Refrigerator** – Energy efficient appliance rebate $50.
    - **Freezer** - $25 rebate
    - **Clothes Washer** - $75 rebate.
    - **Bathroom Fan** – All Energy Star models, $50 rebate.

- **Water Heaters -** $300 for Tier 1 Heat Pump Water Heater (HPWH), $500 for Tier 2 (Northern Spec) HPWH. **Home Improvement Program (HIP)** – FortisBC offers several rebates for weatherization, appliances, lighting, and heat pumps for electrically heated homes. Customers who receive rebates through the LiveSmart BC program are ineligible to receive rebates from the HIP.
    - **Envelope** – Add minimum of R20 for ceilings and R10 for walls, basements and crawlspaces. Rebate is $0.25 per square foot
    - **Windows and Doors** – Energy Star rebates are $2.50 per square foot.
    - **Air Source Heat Pump** – Rebates $200 per ton. Ductless heat pump $300 per ton. Packaged terminal heat pump rebates are $100 per ton. Alternatively loans up to $6,500 are available at 4.9 percent interest over 10 years.
    - **Ground source heat pump** – Energy Star, rebate $500 per ton. **Programmable Thermostat** – Limited to five per household. Rebate is 50% up to $20 each.

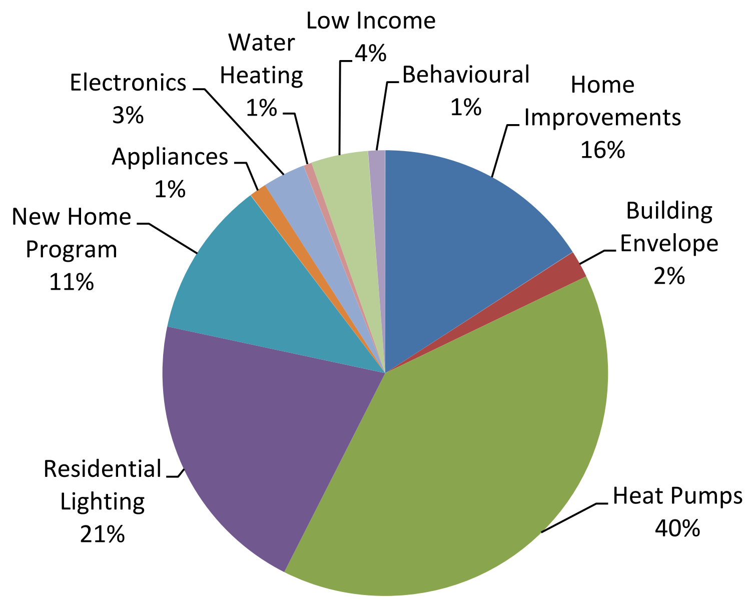
  - **Lighting Rebates** – CFL rebates of 50% up to $2.50 per bulb, CFL fixture 50% up to $10, LED hardwired 50% up to $50, LED bulb 10W or greater 50% or up to $30, LED bulb less than 10W 50% up to $15.
  - **Refrigerator Take Back** - $50 rebate with purchase of qualifying refrigerator. Old unit must be at least 10 years old and minimum 250 litres in gross volume.
  - **Refrigerator** – Energy efficient appliance rebate $50.
  - **Freezer** - $25 rebate
  - **Clothes Washer** - $75 rebate.
  - **Bathroom Fan** – All Energy Star models, $50 rebate.
  - **Water Heaters** - $300 for Tier 1 Heat Pump Water Heater (HPWH), $500 for Tier 2 (Northern Spec) HPWH.
- **Low Income Energy Saving Kit** – includes low flow showerhead, tap aerators, weather strips, foam pipe wrap, window insulator film, outlet and switch gaskets, energy efficient light bulbs and night light, and a fridge and freezer thermometer. Kits are free to qualifying low income customers.

LiveSmart BC Programs

- **Weatherization** – FortisBC offers rebates for wall, floor and attic insulation, based on the area insulated.
- **Ventilation** – Installation or replacement of bathroom fan for rebate or $25.
- **Air Tightness** – Home air sealing (draftproofing) for rebate up to $400.

Figure 5 illustrates the share of historic energy savings by measure category. A significant share of historic savings is from heat pump installations.

Figure 5
Residential Energy Efficiency Program Achievements 2006-2012



Commercial (General Service) Incentives

PowerSense

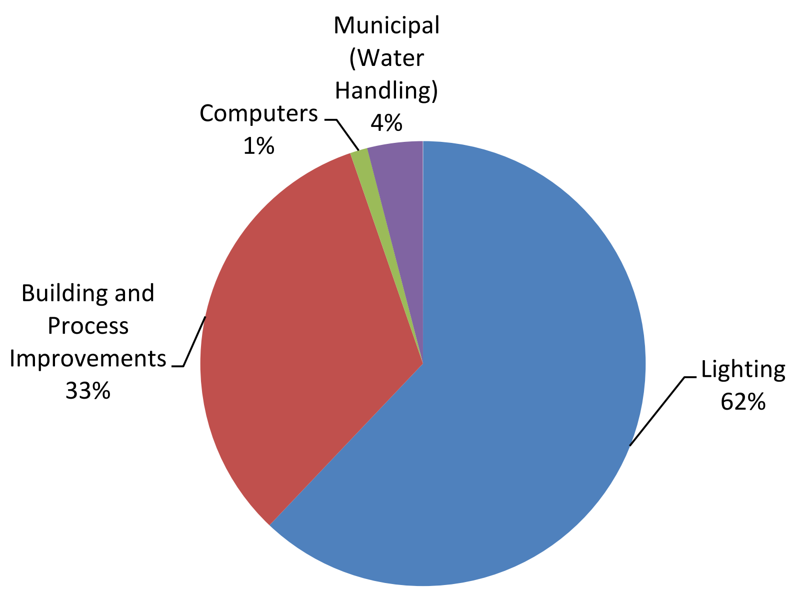
Commercial building energy efficiency programs include the following:

- **Lighting** – FortisBC has provided rebates for compact fluorescent lighting, electronic ballasts, reflectorized luminaries, T8/T5 fluorescents, LED and CFL exit lights, high density discharge lighting, and motion sensors or other lighting control systems. The direct install FLIP program, for small commercial customers, closed as of March 2013.
- **New Building** – PowerSense encourages developers to meet or exceed the technical guidelines of the BC Building Code for new buildings) by at least 25%. ASHRAE 90.1 (2004), the Energy Standard for Buildings except low-rise residential buildings, is the BC building code requirement.
- **Existing Buildings** – Qualified customers can take advantage of a free walk-through energy audit conducted by a FortisBC technical advisor to identify where conservation opportunities exist. If required, FortisBC will fund up to 50 percent, to a maximum of $5,000, of an approved consultant's fee to conduct a comprehensive energy study. Possible technologies include lighting, HVAC control systems or variable speed drives, water heating, refrigeration measures, building envelope, and motors.

- **Rebate structure –** General Service rebates are the lesser of:
    - Ten cents per annual kWh saved;
    - 50% of installed retrofit cost;
        - 100% of incremental cost for new construction; or
    - Amount necessary to achieve a two-year payback.

Figure 6 illustrates the share of historic commercial energy efficiency achievements. Commercial lighting makes up over half of historic achievement.

Figure 6
Commercial Energy Efficiency Program Achievements 2006-2012



Industrial Incentives

PowerSense

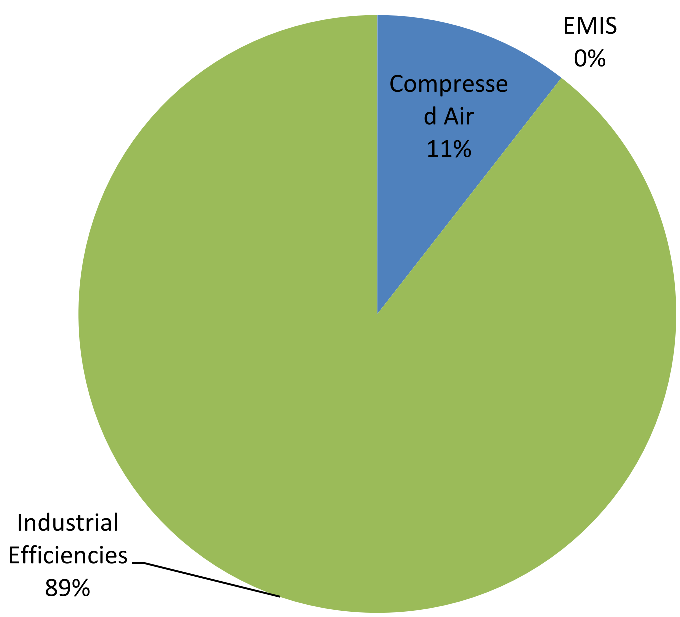
Industrial building energy efficiency programs include the following:

- **Walk Though Audit**– FortisBC offers a free walk through energy audit by a technical advisor to identify where potential energy savings opportunities exist. In cases where a more detailed assessment is required, FortisBC will cover 50% of the cost for an approved consultant. Energy efficiency measures may include motor upgrades, air compressor upgrades, process or non-process energy savings, pumps and fans, variable frequency drives, or other measures.

- **Industrial Efficiency** – A technical advisor or an approved consultant is available to assess existing or new process design, or building systems (lighting, compressed air etc.). Rebates are available for suggested technology upgrades for approved energy efficiency measures.
- **Rebate Structure** – the same as for Commercial (General Service) customers.

Figure 7 illustrates the share of historic industrial energy efficiency savings.

Figure 7
Share of Industrial Energy Efficiency Achievements 2006-2012



Irrigation and Municipal Infrastructure

PowerSense

FortisBC offers audits or incentives up to 100% of an approved consultant's fee for energy audits in irrigation, and municipal water handling infrastructure. Financial incentives based on ten cents per kWh saved are available for identified projects up to 50 percent of the incremental project cost or the amount required for a 2-year payback, whichever is less. The following areas are available for energy savings:

- **Irrigation** – Pumping systems can achieve increased energy efficiency through motor downsizes, pump upgrades, variable speed drives, digital control, or other equipment. Rebates are limited to 50 percent of project costs.

- **Water and Waste Water Treatment** – Annual capital improvement programs provide opportunities for energy efficiency upgrades that benefit ratepayers. FortisBC currently has agreements with each municipality to review energy efficiency potential each year. See Partners in Efficiency Program below.

- **Traffic and Street Lighting** – Similar to water and wastewater treatment agreements, energy efficiency is included in the annual capital improvement plan for city lighting. Due to successful past programs, virtually all traffic lights in FortisBC's service territory are already updated to LED technology. A similar opportunity is available for municipal street lighting.

Partner in Efficiency

FortisBC enters into a Partners in Efficiency (PIE) agreement with institutional, commercial, and industrial (ICI) customers such as schools, municipalities, hospitals, and other large commercial and industrial accounts. The PIE is a signed agreement that involves the following:

- Customer agreement to review their capital expenditure plan with FortisBC on an annual basis to identify key projects to improve energy use;
- FortisBC works with the customer to determine the economics for energy efficient upgrades to the project;
- Recommendations for improvements are presented with estimated incremental costs, savings, applicable rebates;
- 50% of estimated rebates are presented upon project completion; and
- The remaining incentive is paid upon completion of satisfactory Measurement and Validation (M&V) protocols to prove the energy savings.

Summary

FortisBC has a strong history in energy efficiency achievement through its programs. FortisBC programs target energy efficiency across all customer classes including indirect customers served by municipal wholesalers. Energy efficiency programs target improvements in major end-uses from a whole-building or system perspective providing comprehensive efficiency upgrades. In addition, the Partner in Efficiency agreement continues energy efficiency conversations from year to year providing flexibility within each program for technology advancements.

End-Use Forecast

Introduction

End-use energy and peak demand forecasts were developed for residential, commercial, and industrial classes for the 2010 CDPR. The 2013 CDPR updated the end-use forecast model based on new customer class load growth rates. The end-use forecasts are used as input for the conservation potential model. This section summarizes the methodology and assumptions for the end-use load forecasts. The end-use forecast includes all customers, both direct and indirect, that are served by FortisBC.

Residential End-Use Forecast

Methodology

End-use consumption for residential customers was estimated based mainly on the 2009 Residential End-Use survey results. Appliance saturations, heating types and fuels as well as hours of use are used to define building characteristics. For instance, the number of refrigerators in single family homes built prior to 1976 was calculated from the survey data. Next, an average annual use (refrigerators) was applied to the number of units. The result is energy consumption for refrigerators in single family homes built prior to 1976. This method is applied to all energy consuming appliances and housing types by vintage given the results of the 2009 end-use survey.

Average use data for each electricity-consuming appliance was obtained from a combination of the BC Hydro 2007 Conservation Study as well as FortisBC's survey. The BC Hydro data is used to determine the average annual electricity use by building type, vintage, and heating fuel (i.e. single family, pre-1976, electrically heated). Average use from the FortisBC Survey is used to benchmark how well the BC Hydro data describes FortisBC customer energy consumption. Overall, the BC Hydro average use data applied to FortisBC housing characteristics results in average customer use by building type (single family, apartment, etc.). The average use by building type is similar to the average use estimated by the FortisBC survey.

Housing Unit Forecast

Table 1 summarizes the housing forecast (units) and energy use over the planning period. The housing unit forecast was developed based on customer growth rates, demolition rates, and the 2009 end-use survey. The MWh forecast is the results of applying appliance consumption data to FortisBC building characteristics as described above.

Table 1
Residential Housing Unit and Energy Forecast

	Single Family	Manufactured Home	Row House	Apartment	Total	Growth Rate	Forecast MWh	Growth Rate
2014	102,076	11,500	22,276	16,008	151,860	0.1%	1,825,130	0.5%
2015	102,124	11,503	22,372	16,017	152,016	0.1%	1,839,277	0.8%
2016	102,364	11,518	22,847	16,050	152,779	0.5%	1,850,941	0.6%
2017	102,507	11,527	23,136	16,071	153,241	0.3%	1,863,074	0.7%
2018	102,649	11,536	23,428	16,091	153,705	0.3%	1,875,029	0.6%
2019	102,789	11,546	23,723	16,112	154,170	0.3%	1,887,021	0.6%
2020	102,928	11,555	24,020	16,133	154,636	0.3%	1,899,050	0.6%
2021	103,065	11,564	24,320	16,154	155,104	0.3%	1,911,117	0.6%
2022	103,201	11,573	24,623	16,175	155,573	0.3%	1,923,221	0.6%
2023	103,335	11,583	24,929	16,196	156,043	0.3%	1,935,362	0.6%
2024	103,468	11,592	25,237	16,218	156,515	0.3%	1,947,540	0.6%
2025	103,600	11,602	25,548	16,239	156,988	0.3%	1,959,755	0.6%
2026	103,729	11,611	25,862	16,260	157,462	0.3%	1,972,007	0.6%
2027	103,858	11,620	26,179	16,281	157,938	0.3%	1,984,297	0.6%
2028	103,985	11,630	26,498	16,303	158,416	0.3%	1,996,638	0.6%
2029	104,112	11,639	26,819	16,324	158,894	0.3%	2,009,095	0.6%
2030	104,245	11,644	27,140	16,345	159,375	0.3%	2,019,240	0.5%
2031	104,377	11,649	27,463	16,367	159,856	0.3%	2,029,430	0.5%
2032	104,511	11,654	27,786	16,389	160,339	0.3%	2,039,663	0.5%
2033	104,644	11,659	28,111	16,410	160,824	0.3%	2,049,938	0.5%

End-Use Results

Figure 8 summarizes electric energy use for 2014.

Figure 8
Residential 2014 End-Use Energy Consumption
1,720 GWh

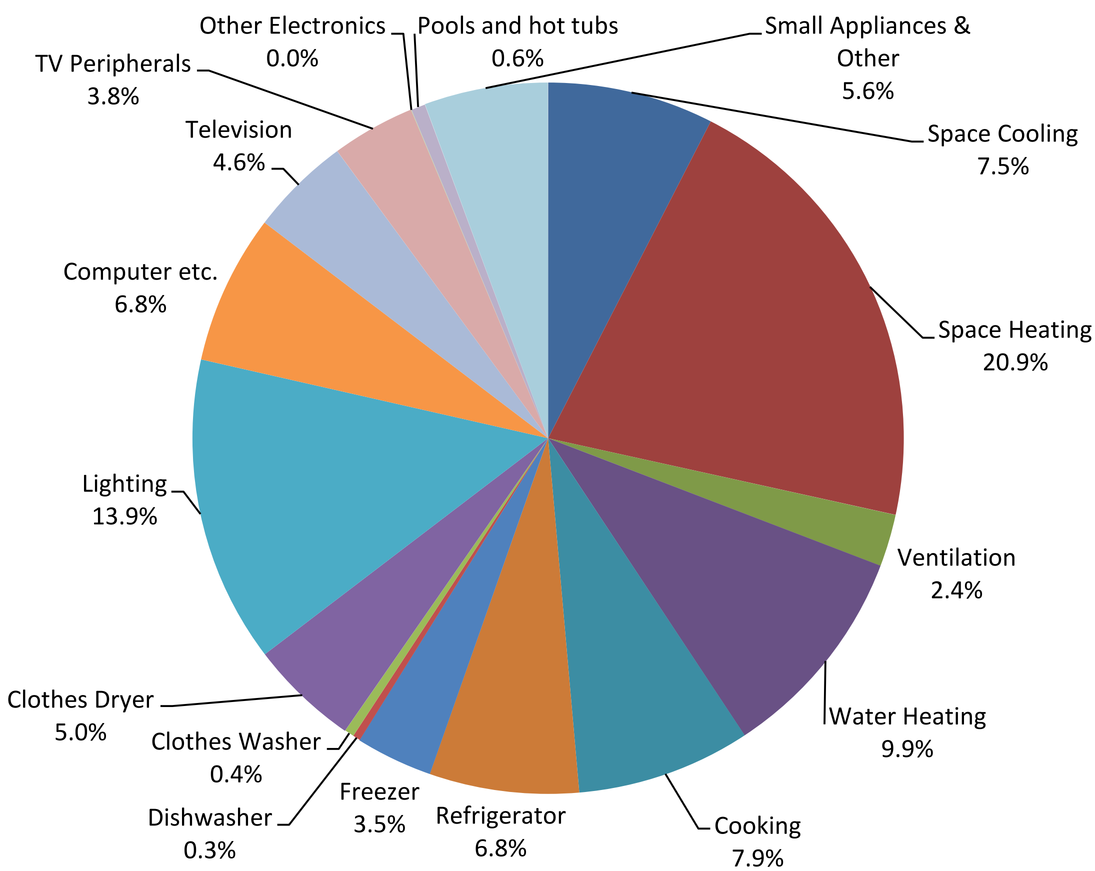
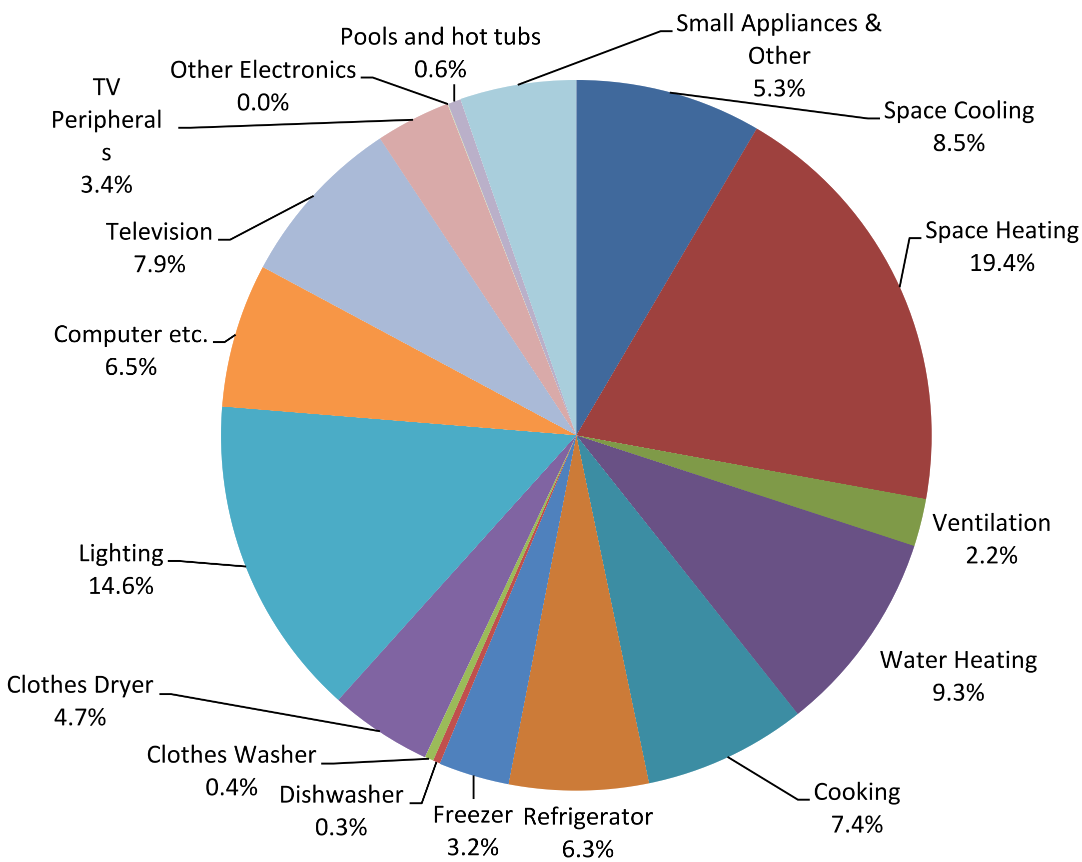


Figure 9 summarizes the end-use electricity consumption for the last year of the study, 2033. The end-use forecast does not include additional investments in energy efficiency.

Figure 9
Residential 2033 End-Use Energy Consumption
2,056 GWh



Commercial End-Use Forecast - Energy

Methodology

The end-use forecast for commercial buildings was calculated according to the following steps:

1. Estimate the share of commercial buildings for each commercial building type (i.e. restaurant, office, retail etc) from FortisBC survey data;
2. Estimate the average square footage for each building type and benchmark against FortisBC survey data;
3. Utilize publicly available sources such as BC Hydro's conservation potential study (2007), FortisBC survey results, and the Northwest Power and Conservation Council for end-use intensity data (EUI data) in kWh/square foot;

4. Using the known number of commercial customers, estimate the number of customer per building so that the number of buildings can be estimated
5. Calibrate the number of buildings so that total end-use consumption matches weather adjusted load;
    a. EUI data is multiplied by estimated square foot data calculated using the number of buildings (calibrated) and average square footage by building type
6. Compare average customer use from end-use forecast model with average commercial consumption (actual or forecast data);
7. Forecast commercial square footage through 2030 by building type;
8. Forecast EUI for each end-use by building type;
9. Apply EUI to forecast of commercial floor space.

The equation form of this methodology is shown below:

$$\text{weather adjusted load} = \sum_{s=1}^{n=segments} \text{Buildings} \times \left(\% \ \frac{\text{Buildings}}{\text{Segment}}\right) \text{x} \left(\frac{\text{SqFt}}{\text{Building}}\right) \text{x(EUI)}$$

The weather adjusted load is equal to the sum of the load in each of the commercial building segments. The key calibration variable is the number of buildings per customer. This process was completed using 2008 as the base year. Because building characteristics change very slowly over time, the 2008 data is relevant for this study.

Assumptions

FortisBC survey data was used to estimate the share of buildings that are restaurants, offices, hospitals, etc. To estimate the breakdown of buildings the Commercial End Use Survey report is used.[2] Buildings were categorized as shown in Table 2 below. The following assumptions were made to calculate the breakdown of buildings in Figure 10 below.

- Light industrial buildings are excluded
- Other includes theatres, auditoriums, churches, museums, community and recreation centers and other buildings not in the major categories
- Mixed use commercial buildings were split between offices, retail, and restaurants based on the building function designated in the survey (i.e. personal services, retail trade, eating and drinking establishments etc)
- Five customers from industrial rate class schedules are included in commercial. These include City of Kelowna, Whitewater Ski Resort, UBC Okanagan, Selkirk College, and Trail Community Health (hospital).

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[2] FortisBC Inc. *2009 Commercial End-Use Study*. Discovery Research. August 2009. Page 17.

Figure 10
Commercial Building Breakdown, Number of Buildings

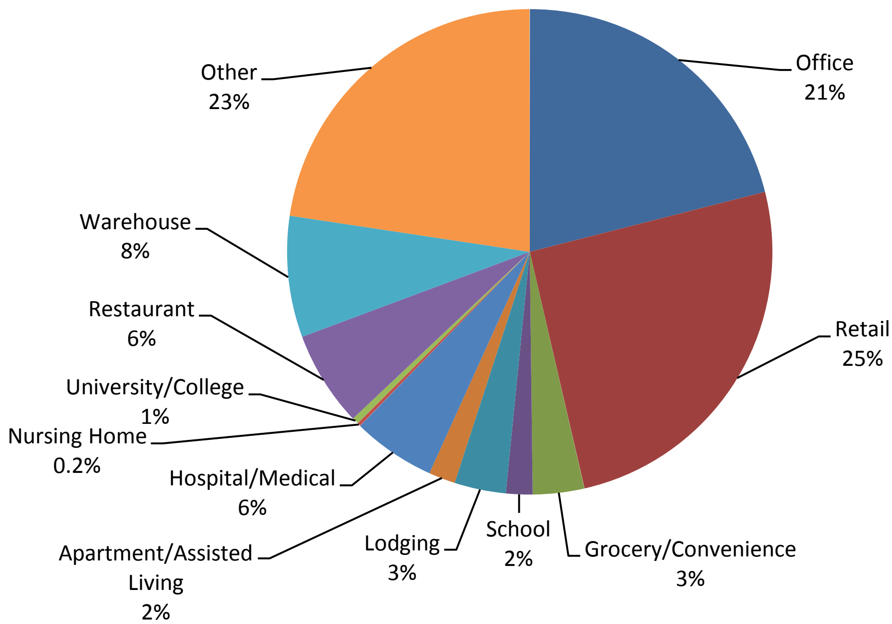


Table 2 defines the building types used in the analysis.

Table 2
Commercial Building Definitions

Building Category	Square Feet
Large Office	>100,000
Medium Office	50,000 to 100,000
Small Office	<50,000
Retail:	
Large Non-Food Retail	>100,000
Medium Non-Food Retail	50,000 to 100,000
Small Non-Food Retail	<50,000
Large Hotel	>100,000
Medium Hotel/Motel	50,000 to 100,000
Large School	>50,000
Medium School	25,000 to 50,000

EUI Data

The end-use forecast uses primarily EUI data from BC Hydro's 2007 study. The BC Hydro data corresponds to buildings in BC Hydro's "Southern Interior," or the climate zone most similar to FortisBC's climate. EUI data from the Northwest Power and Conservation Council was also considered but ultimately not incorporated since BC Hydro data is considered to better represent FortisBC data given that both territories are located in Canada and in similar climate zones. The table below shows FortisBC and BC Hydro EUI data by building type. Data from the

NWPCC is also included for reference. The resulting average use per building is 187,821 kWh per year. Average use per customer is approximately 60,000 kWh per year.[3]

Table 3 compares EUI data by commercial building type.

Table 3
Building EUI Data, Annual kWh/Square Foot

	FortisBC End-Use Model	BC Hydro Southern Interior	NWPCC*
Large Office	22.0	22.0	16.4
Medium Office	18.5	18.5	15.4
Small Office	15.1	15.1	14.0
Large Retail	26.9	26.9	30.9
Medium Retail	24.5	24.5	15.2
Small Retail	18.9	18.9	12.9
Large Hotel	19.8	19.8	19.9
Medium Hotel/Motel	16.7	16.7	19.9
Large School	11.1	11.1	8.4
Medium School	8.7	8.7	8.4
Grocery/Convenience	58.3	58.3	53.7
Apartment/Assisted Living	13.4	13.4	19.9
Medical	27.7	27.7	17.8
Hospital	24.3	24.3	24.7
Nursing Home	13.4	13.4	19.9
University/College	17.7	17.7	17.9
Restaurant	66.1	66.1	41.6
Warehouse/Wholesale	16.4	16.4	5.8
Other	15.4	15.4	15.8

*For comparison purposes only.

Model Calibration

The next step is to calibrate the total number of commercial buildings so that the calculated total consumption matches the actual weather adjusted load. As mentioned previously, the model calibration was conducted for 2008 and is still relevant as the data was obtained within 5 years of this study. Next, the share of buildings is applied to the total number of buildings for which FortisBC provides service. Table 4 shows the results of model calibration in terms of the number of buildings and square footage. In segments where the number of buildings is known the model uses fixed values; for the unknown segments, the number of building is estimated based on the *Commercial End-Use Survey*.

[3] FortisBC general service customers consumed an average of 59,000 kWh per year, lower than the forecast suggests. The difference could be attributed to wholesale commercial customers having higher average use.

Table 4
FortisBC Commercial Building Square Footage
Based on 2008 and 2012 Data

Building Type	Share of Buildings	Number of Buildings	Average Square Feet	Total Square Feet
Large Office	0.0%	5	NA	490,000
Medium Office	0.8%	41	50,000	2,068,492
Small Office	20.2%	1,089	4,000	4,355,504
Large Non-Food Retail	0.0%	-	NA	-
Medium Non-Food Retail	0.0%	5	70,000	350,000
Small Non-Food Retail	25.4%	1,369	9,314	12,746,742
Large Hotel	0.0%	-	NA	-
Medium Hotel/Motel	3.4%	185	8,540	1,580,422
Large School	0.0%	-	NA	-
Medium School	1.8%	96	7,000	668,608
Grocery/Convenience	3.4%	185	9,300	1,721,069
Apartment/Assisted Living	1.8%	96	6,819	651,320
Medical	5.5%	298	6,000	1,790,915
Hospital	0.1%	1	169,732	169,732
Nursing Home	0.2%	12	5,800	69,249
University/College	0.4%	24	39,732	953,568
Restaurant/Tavern	6.3%	342	4,544	1,552,986
Warehouse/Wholesale	8.1%	436	9,339	4,069,836
Other	22.6%	1,221	14,200	17,335,456
Total	**100%**	**5,397**		**50,573,898**

Some of the above categories have sub categories by building size (Office, Non-Food Retail, Hotels etc.) FortisBC's customer surveys were used to determine what share of buildings fit into the size bins (shown in Table 4). According to the survey, the great majority of buildings are small to medium sized and less than 5% of all buildings with more than 50,000 square feet.

Forecast and Results

Once the number of buildings was established, a forecast growth rate was estimated based on FortisBC's forecast of commercial load. The building forecast (in square feet) and end-use data are combined to determine the end-use forecast. Figure 11 shows estimated 2014 consumption by end-use while Figure 12 shows 2033 end-use consumption.

Figure 11
2014 End-Use Consumption - Commercial
1,200 GWh

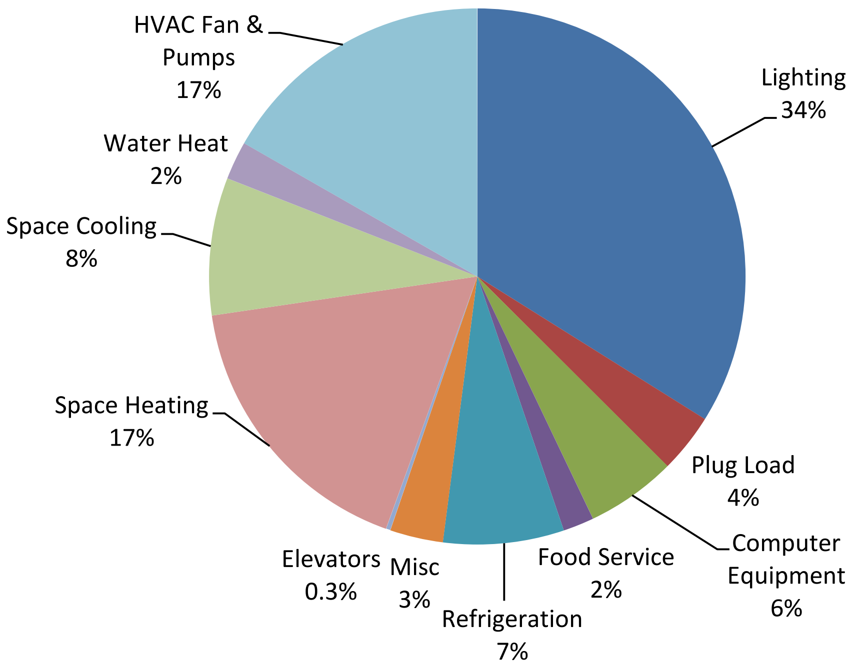
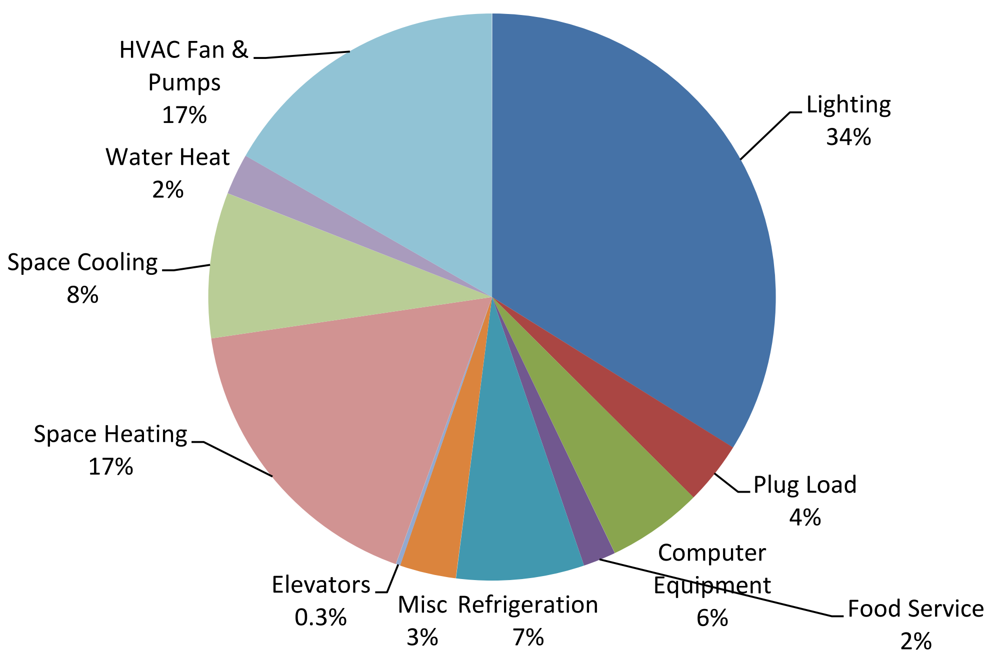


Figure 12
2033 End-Use Consumption - Commercial
1,400 GWh



Figures 11 and 12 are similar because the EUI data for the buildings was forecasted to remain the same over the period. The EUI data were not adjusted to include energy efficiency or code changes. Change in future EUI or EUI for new buildings is accounted for in the conservation potential estimates. Energy efficiency potential due to code changes is later separated from potential available through utility programs.

Commercial End-Use Forecast – Demand

Methodology

The end-use forecast for energy was used together with load factors to estimate peak demand consumption for both the winter peak and the summer peak. The winter peak estimate is calculated by applying BC Hydro demand (kW) by end-use to FortisBC energy consumption across building types. The summer peak utilizes load factors from the Northwest Power and Conservation Council with some adjustments to account for FortisBC climate and other characteristics. Figures 13 and 14 summarize the winter and summer peak demand by end-use forecasts. Note that irrigation consumption is not included in the commercial end-use forecast.

Figure 13
Commercial Winter Peak Demand by End-Use
2014: 225 MW

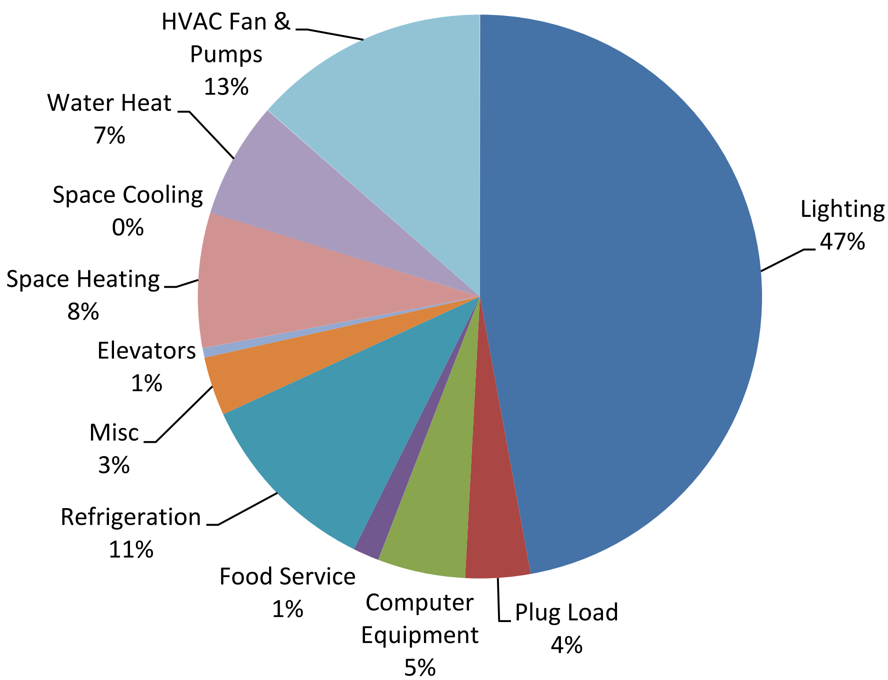
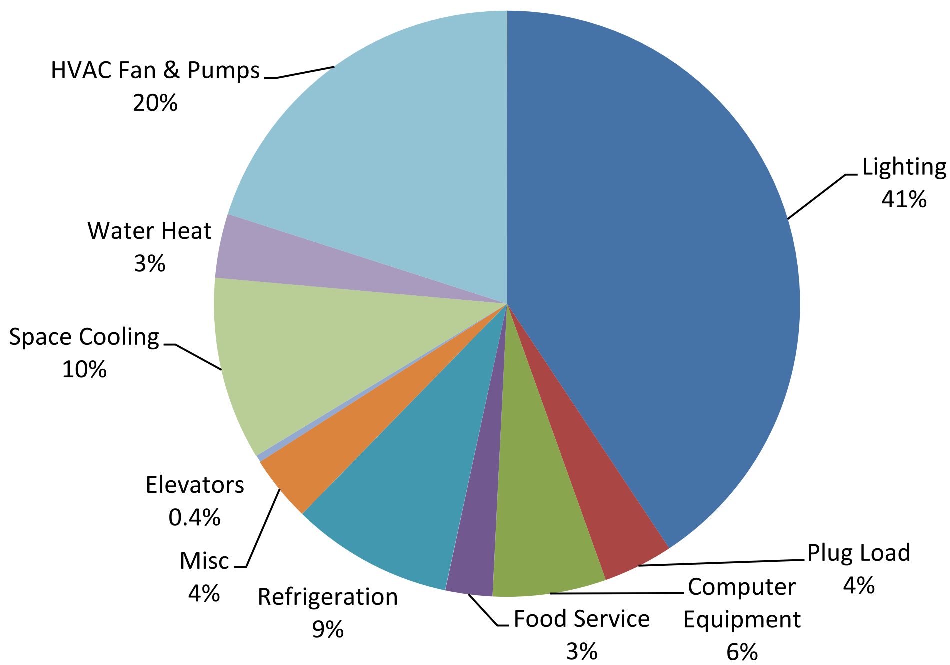


Figure 14
Commercial Summer Peak Demand by End-Use
2014: 190 MW



Industrial End-Use Forecast

Methodology

The base year for industrial sector consumption is calculated using the 2012 energy use and forecast for rate schedules 30, 31, and 33. As mentioned in the Commercial End-Use Forecast section, five customers were removed from the industrial rate class for conservation modeling purposes: City of Kelowna, Whitewater Ski Resort, UBC Okanagan, Selkirk College, and Trail Community Health. Some industrial customers are net metered; self-generation is not included in this forecast nor is it included in the FortisBC system forecast.

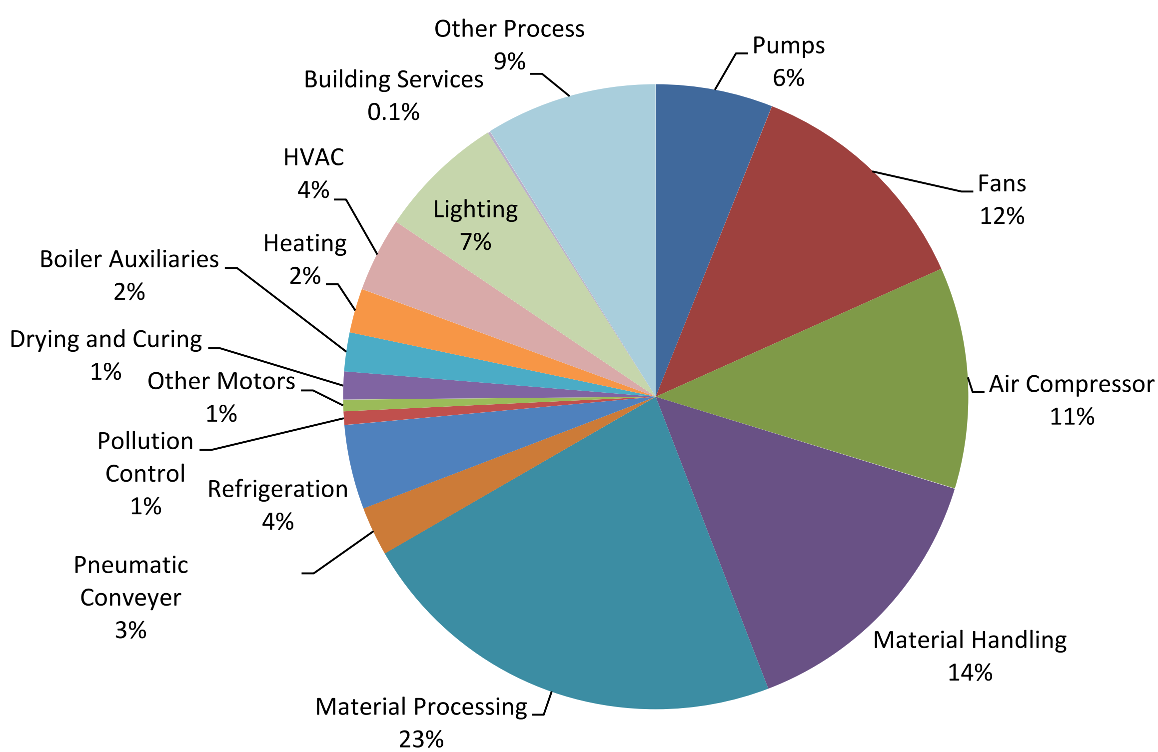
Customer consumption is grouped into classes according to the North America Industry Classification System (NAICS). Table 5 shows the industrial processes and annual kWh consumption for these customers.

Table 5
Industrial Sector Retail Sales by Segment, 2012

Industrial Process	Energy Consumption kWh
Wood Products	122,644,580
Contractors & Construction	4,395,020
Mining	6,792,020
Fruit Packers and Storage	8,831,160
Food and Beverage	11,116,980
Pulp	14,488,572
Building Materials	57,559,950
Other Manufacturing/Servers	4,770,360
Miscellaneous	13,311,390
Total	**243,910,032**

Consumption within each industrial process was disaggregated into end-use by applying percentages from sources such as the BC Hydro Conservation Potential Assessment and the Northwest Power and Conservation Council. The result is a top-down methodology for classifying energy consumption by end-use. Figure 15 summarizes the industrial end-use forecast results.

Figure 15
Industrial End-Use Forecast, Energy
244 GWh



Peak Demand Forecasts

Winter and summer coincident peak demand for the industrial sector is estimated based on historical load factors by customer from FortisBC billing data as well as load factors for industries in California and British Columbia (BC Hydro). The methodology for forecasting peak demand by end use was first to calculate load factors for each type of industry (sawmill, pulp, manufacturing, etc). These load factors are applied to each end-use by industry. In cases where more details were known, such as refrigeration in food and beverage industries, specific load factors were used by end-use. The resulting summer and winter peak demand breakdowns for the base year are given in Figures 16 and 17. Since a 0% growth is assumed for the energy forecast, the 2033 peak demand breakdowns will be identical to Figures 15 and 16, and therefore are excluded from the report.

Figure 16
Industrial Winter Peak Demand by End-Use
2014: 107 MW

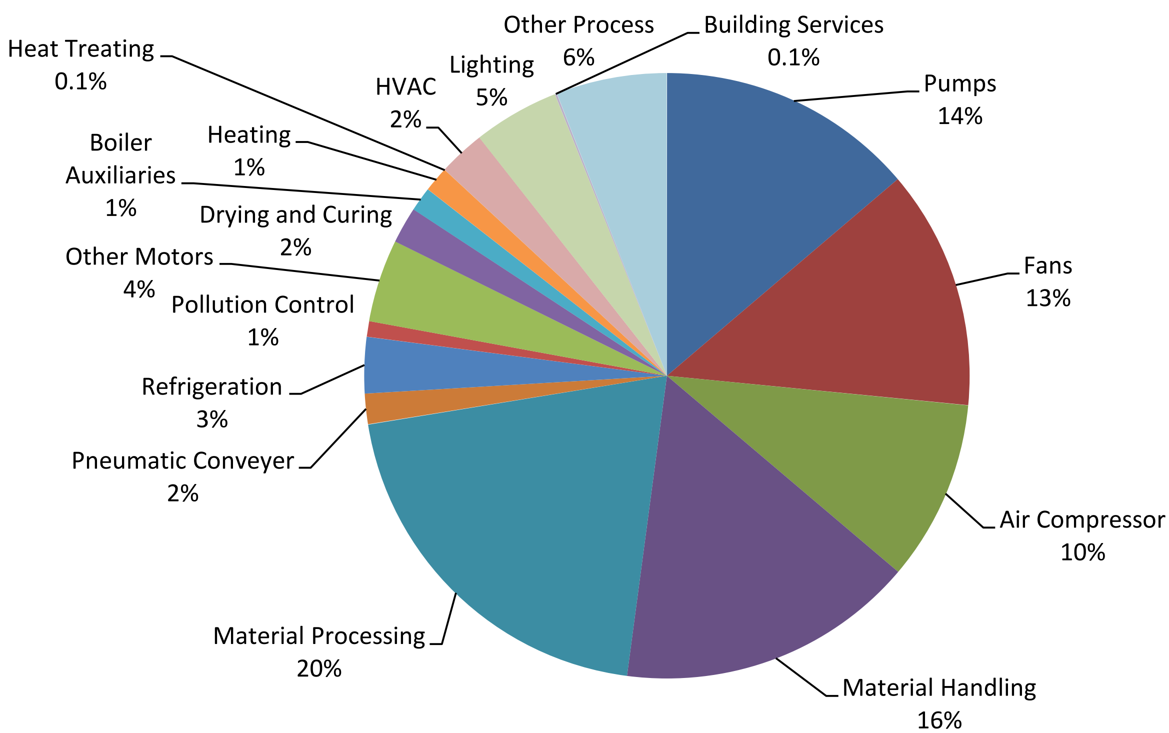
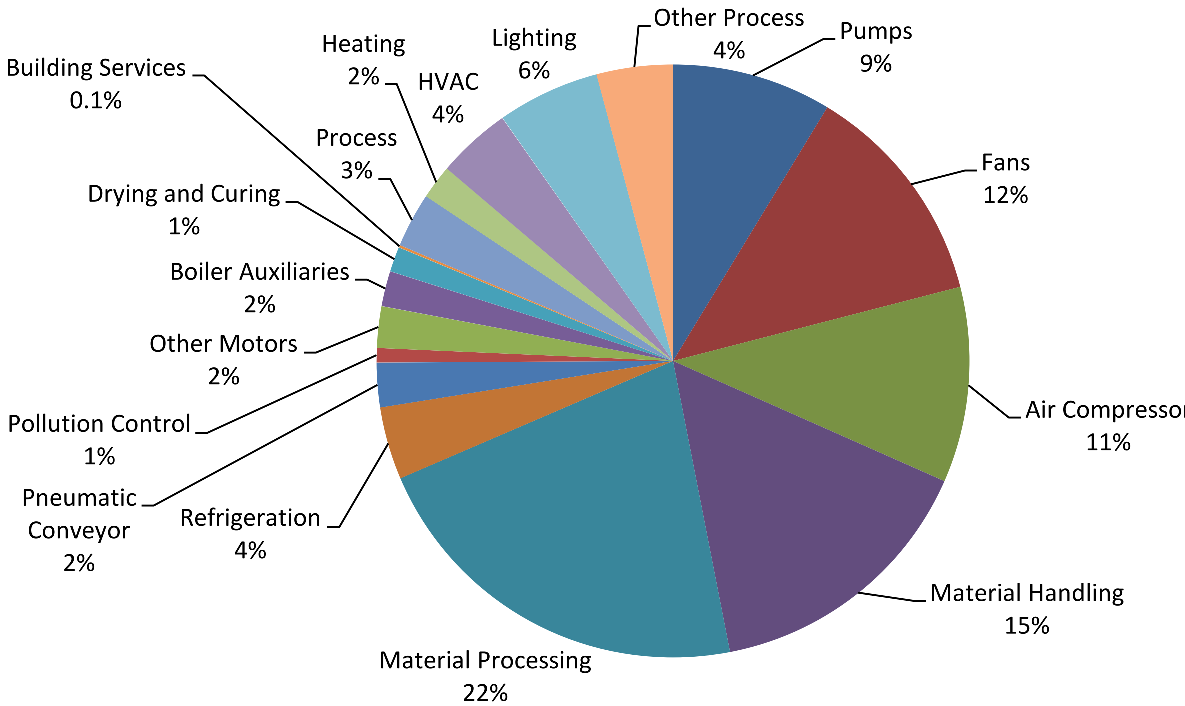


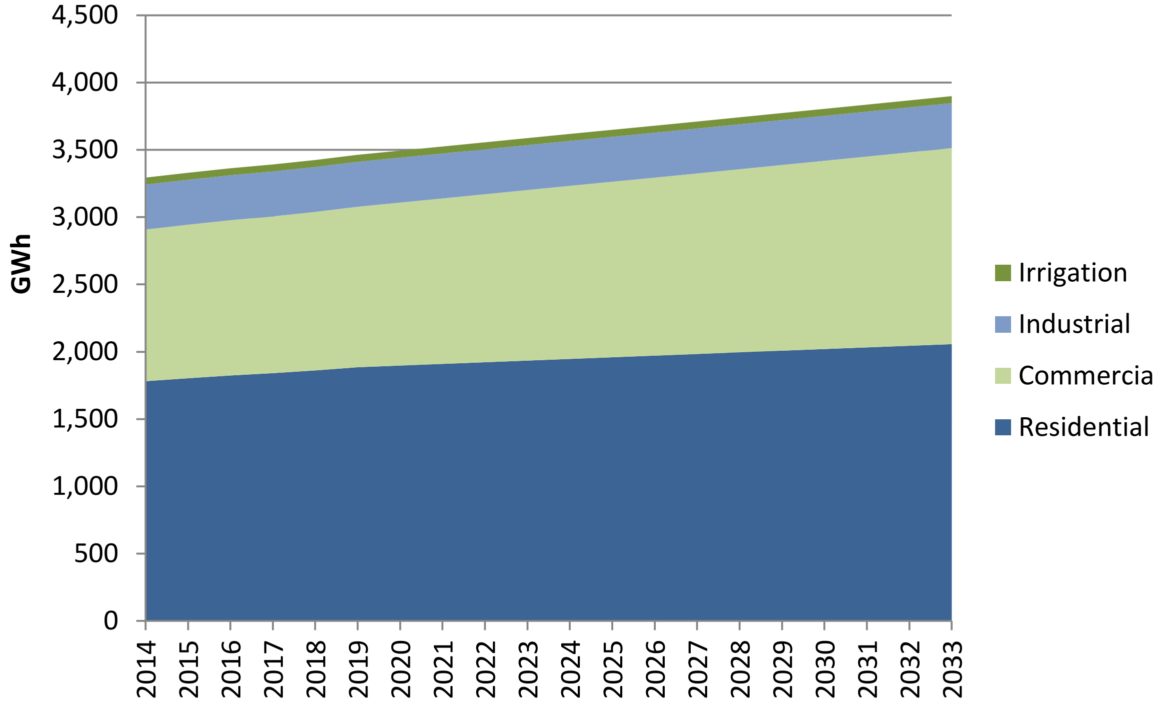
Figure 17
Industrial Summer Peak Demand by End-Use
2014: 38 MW



Total System Forecast

This section aggregates all sectors to compare the end-use forecasting models with the load data provided by FortisBC and its wholesale customers. Figure 18 summarizes the load forecast by sector (excluding losses) for the period 2014 through 2033.

Figure 18
Load Forecast by Customer Class



The irrigation and industrial class load growth is zero percent over the period. Losses are not included in Figure 18.

Scenarios

The 2013 CDPR includes analysis of three scenarios for conservation potential. The three scenarios present a range of potential based on varying specific assumptions. This section discusses the variables used in the scenario analysis and defines each scenario.

Variables

The three scenarios result in different levels of conservation potential or utility costs due to varying four main assumptions: avoided cost of energy, conservation program administration costs, utility incentives, and achievability rates. These variables are discussed below.

Avoided Cost of Energy

The avoided cost of energy affects which measures are cost-effective. Higher avoided costs will result in more measures passing the total resource cost test. The avoided cost of energy is usually based on the cost of alternative resources. Alternative resources may include specific resources such as a power purchase agreement or proposed generating plant or a forecast of market prices. The planning period for this study is 20 years; therefore, the cost of alternative resources must be forecasted over this time period. Because there is significant uncertainty in long-term price forecasts, FortisBC selected a range of avoided costs to reflect possible futures. The scenarios modeled include avoided costs that range from $56.61/MWh market based price forecast in the Pacific Northwest to $128.80/MWh based on BC Clean Energy. The figures are given in levelized cost terms, so they can be used for varying measure lifespans.

As mandated by the British Columbia Ministry of Energy 2011 DSM Regulation, FortisBC uses a market price forecast for the majority (90%) of its measures; and the provincial BC “clean” energy price for the remaining 10% of measures that require a lift through the prescribed modified TRC. The avoided energy costs are used to value firm energy, inclusive of capacity, plus a $35/kW-year adder for avoided transmission and distribution deferred Capital Expenditure savings.

Program Administration Costs

The second variable also affects the cost-effectiveness of conservation measures. In conservation potential modeling, program administration costs are generally expressed as a percent of measure capital costs. Higher program administration costs will reduce the cost-effectiveness of measures evaluated using the total resource cost test. The NWPCC uses 20 percent as the default program administration cost assumption for utility programs. Many factors affect program administration costs including measure type, labour costs, customer perception of conservation programs, service area income and economic growth, and province or federal requirements. FortisBC tracks conservation program expenditures and had determined that program administration costs range from 25 to 30 percent of measure capital costs. These figures, specific to FortisBC, are used to model the conservation scenarios.

Utility Incentive

In practice, utility incentives for conservation programs vary across regions and measures. For the purposes of modeling conservation potential, utility incentives are expressed as a percent of measure capital costs. The utility incentive level has an indirect effect on conservation potential. Specifically, higher utility incentives may increase achievability as more customers are willing to install energy efficient measures at a lower cost. The utility incentive level is adjusted correlating to the achievability adjustment discussed next. Finally the utility incentive directly affects utility program costs. The utility incentive ranges from 40 to 50 percent of measure capital costs. The utility incentive amount does not impact the overall TRC cost effectiveness, but has budget and adoption level impacts.

Achievability Adjustment

Lastly, the scenarios are modeled by adjusting the achievability factor for each measure. In practice, the achievability of conservation measures is related to the relative cost of the measures, type of measure (retrofit or lost opportunity), customer perception of energy efficiency or specific measures, utility incentives, general economic health, or other factors. As mentioned above the achievability factors are adjusted to positively correlate with the utility incentive level in each scenario. The base assumption for achievability is 85 percent over a 20 year planning period. This achievability rate is consistent with the NWPCC assumption for achievability. The achievability rate is multiplied by the achievability adjustment. The adjustment varies from 90 to 100 percent.

Scenario Parameters

Table 6 summarizes the parameters for each scenario modeled in this report.

Table 6
Conservation Potential Scenario Parameters

	Scenario 1	Scenario 2	Scenario 3
Avoided Cost, Levelized $2013/MWh	$56.61	$84.94	$128.80
Program Administration Costs	30%	25%	25%
Utility Incentive	40%	40%	50%
Achievability Adjustment	90%	100%	100%

Scenario 1 will result in the lowest level of conservation potential, Scenario 3 the highest, and the Scenario 2 result is between Scenarios 1 and 3.

Residential Energy Savings Potential

Introduction

This section begins with a brief description of residential customer housing characteristics and appliance saturations. Next, energy efficiency measures are described followed by potential estimates calculated using the methodology described in the "Methodology" section of this report. The conservation potential results are presented for each of the three scenarios described in the previous section.

Residential Customer Characteristics

FortisBC provides residential electric service directly to 112,096 customers and indirectly to an additional 30,842 customers through its wholesale customers. In 2009, FortisBC conducted a customer survey of both direct and indirect residential customers within their service territory. The survey is relevant for the 2013 CDPR as building characteristics change slowly over time. Further the baseline characteristics are also adjusted for recent conservation achievement. The surveys defined building characteristics and appliance saturations, type and age. These results are provided at an aggregate level as well as by sub region including West Kootenay/Boundary, South Okanagan, and Central Okanagan (Kelowna). Table 7 summarizes the key building characteristics for all FortisBC customers. Heat type, furnace age, insulation, window, and door characteristics were also defined for these buildings.

Table 7
Residential Building Characteristics

	Single Family	Mobile, Other	Apartment Condo	Duplex, Row, Townhouse
Building Type	**69%**	**8%**	**13%**	**11%**
Electric Heat	31%	27%	80%	42%
Gas Heat	57%	47%	18%	57%
Other Heat	12%	26%	2%	1%
Own Home	95%	92%	65%	82%
Before 1950	12%	0%	2%	1%
1950-1975	25%	25%	5%	14%
1976-1985	18%	31%	10%	19%
1986-1995	21%	21%	23%	28%
1996-2009	24%	22%	53%	32%
Full Basement	60%	2%	11%	46%
Partial Basement	12%	1%	2%	8%
Crawlspace	20%	26%	3%	27%
No Basement	8%	71%	85%	19%
Average Size (Sq Ft)	2,250	981	1,187	1,688

Table 8 summarizes key appliance saturations for FortisBC residential customers. The survey also identified the average age for the major appliances; these are shown below when provided for the main appliance.

Table 8
Residential Appliance Saturation

Cooking and Food	Share	Average Age, Years	Electronics	Share
Refrigerator Auto Defrost	90%	7.3	DVD	75%
Chest Freezer	52%	12.6	VCR	52%
Upright Freezer (not part of fridge)	21%	6.9	Digital Cable or Satellite TV	47%
Refrigerator Manual Defrost	20%	8.6	CRT TV <32 inches	61%
Microwave	87%		CRT TV >32 inches	24%
Electric Range (cook top + oven)	81%		LCD Flat Screen TV	38%
Electric Cook Top	11%	9.0	Laser Printer	15%
Gas Range (cook top + oven)	11%		Plasma flat screen TV	13%
Separate Electric Oven	10%		Rear projection TV	7%
Gas Cook Top	5%		Desktop Computer	69%
Cleaning			Inkjet printer	65%
Electric Clothes Dryer	92%	7.8	Laptop computer	49%
Automatic Dishwasher	82%	7.0	Fax	19%
Clothes Washer (top load)	64%	9.5	Audio entertainment video games	24%
Clothes Washer (front load)	35%	3.6	Surround System	32%
Gas Dryer	2%	8.7	Other	2%
Water Heating			**Miscellaneous**	
Gas Water Heater	50%	6.9	Jetted Bathtub	11%
Electric Water Heater	49%	6.6	Hot Tub (outdoor)	11%
AC			Swimming Pool (outdoor)	7%
Central Air Conditioning	50%	N/A	Indoor hot tub	2%
Window AC	16%		Separate workshop	18%
Portable AC	7%		Electric Car Block Heater	21%

Energy Efficiency Measures

Several measures for each end-use were analyzed to model energy efficiency potential. Measures were included where the data available supported cost and savings values. Typically "non-traditional" measures such as shade trees (to reduce air conditioning load) have little solid basis for either cost or savings and so were excluded from this potential assessment.

The table below summarizes the types of technology-based measures included in the analysis. While few categories are provided in the table, several permutations of each measure within these categories are included. There are over a hundred individual measures considered in the residential sector only.

Table 9
Residential Energy Efficiency Measure Categories

Appliances	Domestic Hot Water
Refrigerator and Freezer Recycling	Tank Upgrades
Clothes Washers and Dryers	Low-Flow Showerheads
Dishwashers	Low-Flow Faucet Aerators
Refrigerators and Freezers	Heat Pump Water Heater
Ovens and Ranges	Wastewater Heat Recovery
Microwave	Heating and Cooling
Lighting	Heat Pump Upgrades
Fluorescent Tube Upgrade	Heat Pump Conversions
CFLs	Window and Portable Air Conditioning Upgrades
LEDs	
Electronics	Electric Thermostats
Televisions	ECM on Furnace Fans
Computers and Monitors	Geothermal Heat Pumps
Set Top Boxes	Weatherization
TV Peripherals	Windows
New Home Whole House Measure	Air Sealing
Electric Thermal Storage (ETS)	Insulation

Heat pump conversions are measures that take into account the incremental cost and energy savings from switching from some other electric heat source (like baseboard or forced air furnace) to heat pumps. Conversely, heat pump upgrade measures take into account the incremental cost and savings from upgrading from a less efficient heat pump to a more efficient model.

Emerging Technologies

Some emerging technology measures are included in the potential estimates. Measures such as heat pump water heaters, which are not yet main stream but have equipment available in the market, have been included in the main potential assessment. In addition, whole house measures for new single family homes are included. These are known as EnerGuide80 and Energuide90[4] whole house performance measures and include significant weatherization,

[4] EnerGuide90 homes are also known as "near net zero" homes in British Columbia. Though these homes consume significantly less energy than standard or older homes; they do not attain net zero electricity consumption on an annual basis.

energy efficient heating types and water heating. British Columbia has signaled its intention to adopt EnerGuide80 standards as building codes in late 2014.

EnerGuide90 homes are also known as "near net zero" homes in British Columbia. While the technologies for these homes are available, programs for net zero homes are not yet mature. Net zero homes can be built for $10,000 to $30,000 more than the cost of a conventional home which can eventually be recovered through savings on energy bills and increased value of the home. Currently fifteen EQuillibrium projects were built in Canada through CMHC[5] and eight Super Efficient New homes were recently completed, with FortisBC technical assistance and incentives, for the Penticton Indian Band[6]. EnerGuide 90 projects are included in potential estimates; however, due to the emerging nature of the programs, achievability rates are set conservatively for this measure group (65 percent).

In addition to the emerging technology measures included in this analysis, there are a variety of technologies/measures that are undergoing research and development, and others that have yet to be identified that may come to fruition during the 20-year timeframe of this study.

- Phase change materials – building materials that store thermal energy during the day and release during the night
- Vacuum panel insulation – panels that achieve insulating levels up to 7 times greater than existing materials
- Green roofs – roofing systems capable of growing plants; primarily for multifamily apartment buildings
- Vacuum panel windows – two glass panels with a partial vacuum in between
- Integrated PV windows – windows that incorporate photovoltaic cells in the window
- Advanced LED lighting – LED's are included in the potential estimates, and significant advances and price declines could result in the displacement of CFLs
- Fiber optic lighting and light pipes – day lighting is distributed throughout buildings through fiber optic cable
- Solar absorption cooling – gas-fired absorption chillers are widely available, but these cooling systems use solar energy as the heat source.
- Evaporative cooling – evaporative cooling is becoming more widely available in hot, dry climates and may eventually have some application in FortisBC service area
- Home Automation (optimized home energy use) – Home Automation fully integrated with the smart grid will help to optimize energy consumption and peak demand beyond individual measure savings
- On-site generation (e.g., waste to energy, widespread PV, wind, fuel cell) – to obtain true net zero energy consumption, some on-site generation will likely be required.

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[5] http://www.netzeroliving.ca/#what_is_a_net_zero_homeHC's EQuilibrium initiative

[6]http://fortisbc.com/AlternativeEnergyServices/ProjectCases/SuperEfficientNewConstruction/Pages/EcoSage-project.aspx

The above measures were considered; however, the measures/technologies were found to be either unproven or too costly to be implemented as cost-effective conservation. It is likely that development will continue and some or all will be tested, verified, and included in future potential assessments.

Customer-Owned Renewable Energy

Several customer-owned renewable energy technologies were assessed for this conservation potential study. Customer-owned renewable energy measures include:

- Solar (photovoltaic);
- Wind turbines; and
- Solar hot water heating.

Micro hydro resources are most commonly found as a supply-side resource rather than a demand side measure. Costs and annual generation for these projects vary significantly by site and this study does not attempt to develop the potential for these projects (similarly treated in the BC Hydro DSM study).

Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. Table 10 summarizes the cost-effective achievable energy savings for each of the three scenarios by end-use.

Table 10
20-year Residential Cost-Effective Achievable Energy Savings, MWh

	Scenario 1	Scenario 2	Scenario 3
Building Envelope	39,399	60,522	92,947
Heat Pumps	3,002	13,296	26,072
Residential Lighting	19,298	44,481	43,634
New Home Program	0	0	492
Appliances	10,584	16,642	15,260
Electronics	53,419	81,116	78,259
Water Heating	8,875	16,605	54,062
Other Space Conditioning	2,684	26,355	14,067
Total	137,262	259,018	324,792

These savings are the annual energy savings potential available in 2033. Tables 11 and 12 show the cost-effective and achievable winter and summer peak demand savings for each of the three scenarios.

Table 11 20-year Residential Cost-Effective Achievable Winter Peak Demand Savings, MW			
	Scenario 1	**Scenario 2**	**Scenario 3**
Building Envelope	8.3	12.7	19.5
Heat Pumps	0.6	2.8	5.5
Residential Lighting	1.4	3.2	3.1
New Home Program	0.0	0.0	0.0
Appliances	2.7	3.4	3.3
Electronics	3.3	5.3	5.1
Water Heating	2.3	3.4	10.2
Other Space Conditioning	14.6	22.9	18.6
Total	33.3	53.7	65.3

Table 12 20-year Residential Cost-Effective Achievable Summer Peak Demand Savings, MW			
	Scenario 1	**Scenario 2**	**Scenario 3**
Building Envelope	4.6	7.1	10.9
Heat Pumps	0.4	1.6	3.1
Residential Lighting	0.0	0.0	0.0
New Home Program	0.0	0.0	0.0
Appliances	0.0	0.0	0.0
Electronics	0.0	0.0	0.0
Water Heating	0.0	0.0	0.0
Other Space Conditioning	1.6	2.2	2.1
Total	6.6	10.9	16.1

Program Potential

In order to define utility program achievable potential, or "Program Achievable Potential," ramp rates are assigned by measure category to approximate the amount of energy efficiency potential that could be reasonably obtained through utility program efforts over the planning period. The ramp rates used for program achievable potential can be found in Appendix C. Figures 19 through 21 summarize the annual incremental potential for each scenario. As the avoided cost increases across the scenarios, more measures become cost-effective in each end-use category. Heat pump conversions are economic in only Scenario 3.

Figure 19
Scenario 1 ($56.61/MWh): Residential
Incremental Annual Program Achievable Potential by End-Use

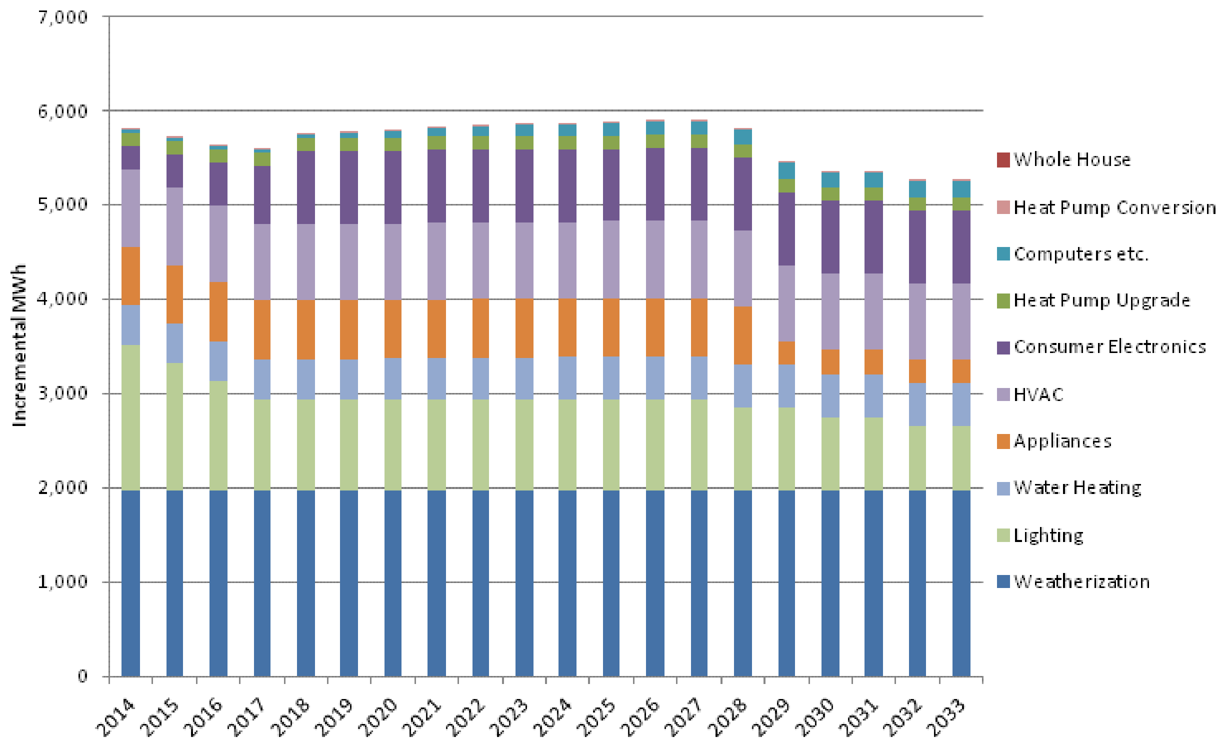


Figure 20
Scenario 2 ($85/MWh): Residential
Incremental Annual Program Achievable Potential by End-Use

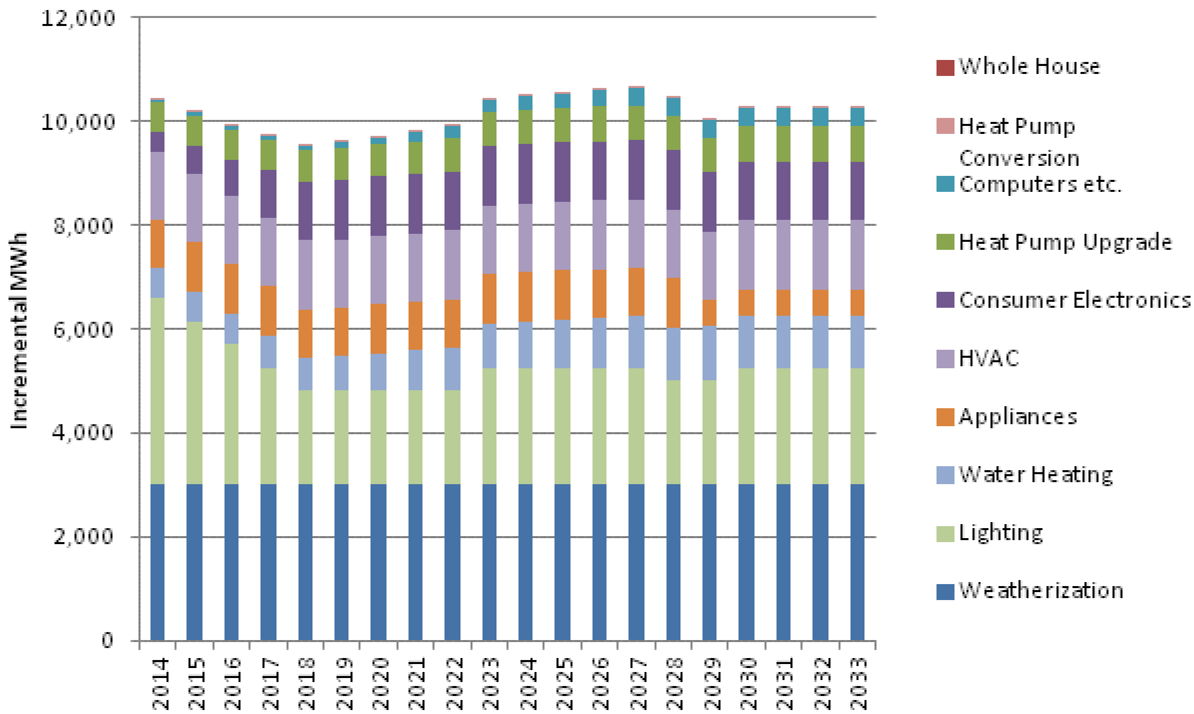


Figure 21
Scenario 3 ($128.80/MWh): Residential
Incremental Annual Program Achievable Potential by End-Use

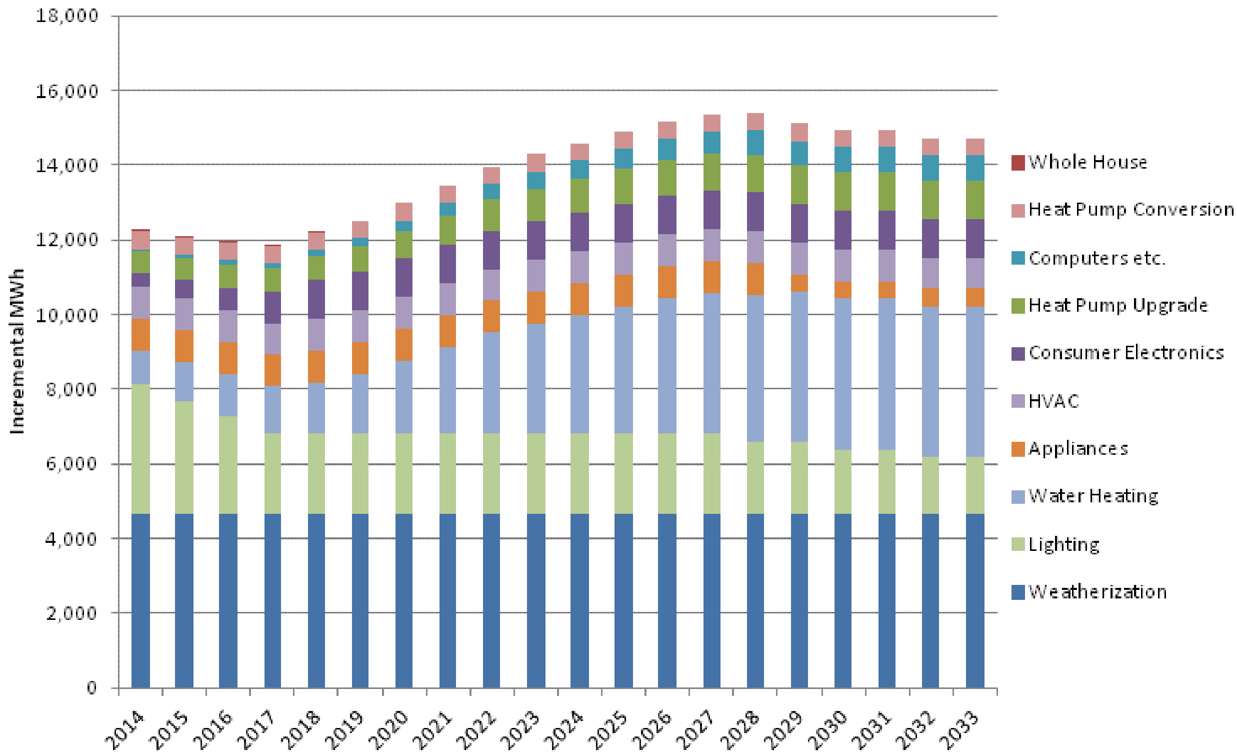


Table 13 shows measure category ramp rates and the associated larger end-use category in the figures above. The ramp rates dictate the pace (over time) that energy efficiency can be achieved. The infrastructure (e.g., availability of contractors) and cost (e.g., first cost, incentive levels) can affect the ramp rate, especially related to new technologies or measures that may take longer to become accepted in the marketplace.

Table 13
Measure Ramp Rates

Measure Category	Ramp Rate	End-Use
Lighting	ResLight	Lighting
Water Heater	EmergTech	Water Heating
Consumer Electronics	Electronics	Consumer Electronics
Other Water Heating	20 Year	Water Heating
Refrigerator	20 Year	Appliances
Computers etc.	EmergTech	Computers etc.
Freezer	15 Year	Appliances
Clothes Washer	15 Year	Appliances
Dishwasher	20 Year	Appliances
Windows	20 Year	Weatherization
Insulation	20 Year	Weatherization
Heat Pump Conversion - Air Source	20 Year	Heat Pump Conversion
HVAC	20 Year	HVAC
Window AC	20 Year	HVAC
Heat Pump Upgrade - Air Source	20 Year	Heat Pump Upgrade
Heat Pump Upgrade - Ductless	EmergTech	Heat Pump Upgrade
Whole House	EnerGuide90/80	Whole House
Electronic Thermostat	20 Year	HVAC

Customer-Owned Renewable Energy

Cost and savings data for renewable energy measures were primarily obtained from the BC Hydro study; however, the NWPCC data base was used to benchmark the cost and savings data.

Technical potential for solar is calculated assuming that 30 percent of single family and row houses and 45 percent of apartment buildings are applicable for solar PV and solar water heating (based on BC Hydro Southern Interior Climate zone). The availability of wind resources is expected to be low. The BC Hydro study assumes an achievability rate of 0.1 percent for residential customer-owned wind generation, and this rate is applied to FortisBC homes as well. Lastly, 45 percent of homes with electric water heaters are assumed to applicable for solar water heat.

At current costs and the highest avoided cost (Scenario 3), none of the above technologies are cost-effective. However, a second scenario was analyzed assuming costs decline by 10 percent per year. Using this declining cost structure and ramp rates to define achievability, economic potential is estimated and shown in the last column of the Table 14. Once a measure is cost effective, the ramp rate begins at 1% of technical potential per year and escalates to 5 or 10 percent of technical potential annually. The effective achievability rates are between 14 and 60 percent depending on when the measure becomes cost-effective.

Table 14 Residential Customer-Owned Renewable Energy 20-Year Potential $2013									
	Annual Generation kWh	Capital Cost	Installation Cost	Annual O&M	Life	TRC BC Ratio at $128.80/MWh	Technical Potential MWh	Economic Potential* MWh	Year Technology Becomes Cost-Effective
Residential 3 kW PV, Detached	3,300	$7,004	$6,367	$191	20	0.26	131,428	18,400	2027
Residential 15 kW PV, Apt	16,500	$21,012	$19,102	$573	20	0.44	121,845	27,415	2021
Residential Wind, 400 W	700	$531	$955	$0	15	0.52	93	55	2018
Solar Hot Water 5 m^3 collector	2,200	$5,306	$0	$1	20	0.52	80,085	39,482	2019

*Assumes decreasing cost trend

Program Costs

The total utility costs are shown in Table 15 below. These costs include only the incentive and program administration costs.

Table 15 Residential Cost-Effective Achievable Potential Total 20 Year Cost ($2013)			
	Scenario 1	Scenario 2	Scenario 3
Building Envelope	7,403,276	$12,892,434	34,485,537
Heat Pumps	837,574	$4,659,336	12,480,438
Residential Lighting	2,393,068	$11,913,550	11,913,550
New Home Program		$0	296,322
Appliances	1,947,119	$3,750,112	3,750,112
Electronics	3,548,571	$6,100,592	6,641,868
Water Heating	1,428,277	$3,551,585	21,121,149
Other Space Conditioning	12,791,825	$23,196,960	17,488,646
Total	30,349,710	$66,064,570	108,177,622

Table 16 presents the first year utility costs for economic and achievable potential. These unit costs do not take measure life into account and include only incentives and program administration costs. The Other Space Conditioning category shows high first year costs since this category include electric thermal storage which is primarily a peak shaving measure.

Table 16 Residential Cost-Effective Achievable First Year Cost, $2013/kWh			
	Scenario 1	**Scenario 2**	**Scenario 3**
Building Envelope	$0.19	$0.21	$0.37
Heat Pumps	$0.28	$0.35	$0.48
Residential Lighting	$0.12	$0.27	$0.27
New Home Program			$0.60
Appliances	$0.18	$0.23	$0.25
Electronics	$0.07	$0.08	$0.08
Water Heating	$0.16	$0.21	$0.39
Other Space Conditioning	$4.77	$0.88	$1.24
Total	$0.22	$0.26	$0.33

Lastly, Table 17 shows the weighted benefit-cost ratios for each of the scenarios by end-use. These weighed benefit-cost ratios are based on the economic and achievable potential which includes potential realized through codes and standards.

Table 17 Residential Measure Weighted Benefit/Cost Ratio			
	Scenario 1	**Scenario 2**	**Scenario 3**
Building Envelope	1.7	2.0	2.2
Heat Pumps	1.1	1.3	1.6
Residential Lighting	3.1	2.9	4.4
New Home Program	NA	NA	1.3
Appliances	3.4	6.2	6.7
Electronics	4.7	6.8	9.8
Water Heating	7.2	6.1	3.2
Other Space Conditioning	2.8	1.4	2.6
Total	3.5	2.9	4.6

Summary

The following compares the energy efficiency potential estimates with the load forecast for the year 2033. The potential in Table 18 below is both economic and achievable and does not include consumer-owned resources.

Table 18 Comparison of Load Forecast and Economic and Achievable Potential Estimates				
	Energy MWh	**Percent of Energy Savings**	**Winter Peak Demand, MW**	**Summer Peak Demand, MW**
2033 Forecast	**2,056,385**		**454.3**	**323.7**
Scenario 1	137,262	6.7%	7.3%	2.0%
Scenario 2	259,018	12.6%	11.8%	3.4%
Scenario 3	324,300	15.8%	14.4%	5.0%

It is estimated that FortisBC could save 6.7 to 15.8 percent of 2033 residential energy consumption with cost-effective conservation measures.

Commercial Energy Efficiency Savings Potential

Introduction

FortisBC commercial customers consume approximately 34 percent of total load (both direct and indirect customers). This section of the report estimates the amount of energy efficiency potential available through these commercial customers. First customer characteristics are summarized using the end-use forecast developed in a previous section and the FortisBC Commercial Customer Survey completed in August 2009. Next, energy efficiency measures are defined followed by a summary of savings potential.

Commercial Customer Characteristics

Building type, heat type, and average building size are the key parameters used to define FortisBC's commercial sector. These parameters are developed and forecasted in the End-Use Consumption Forecast section. Figure 22 summarizes the distribution of building types for FortisBC commercial customers. This data was developed in the end-use forecast and is repeated below for reference.

Figure 22
Commercial Building Breakdown, Number of Buildings

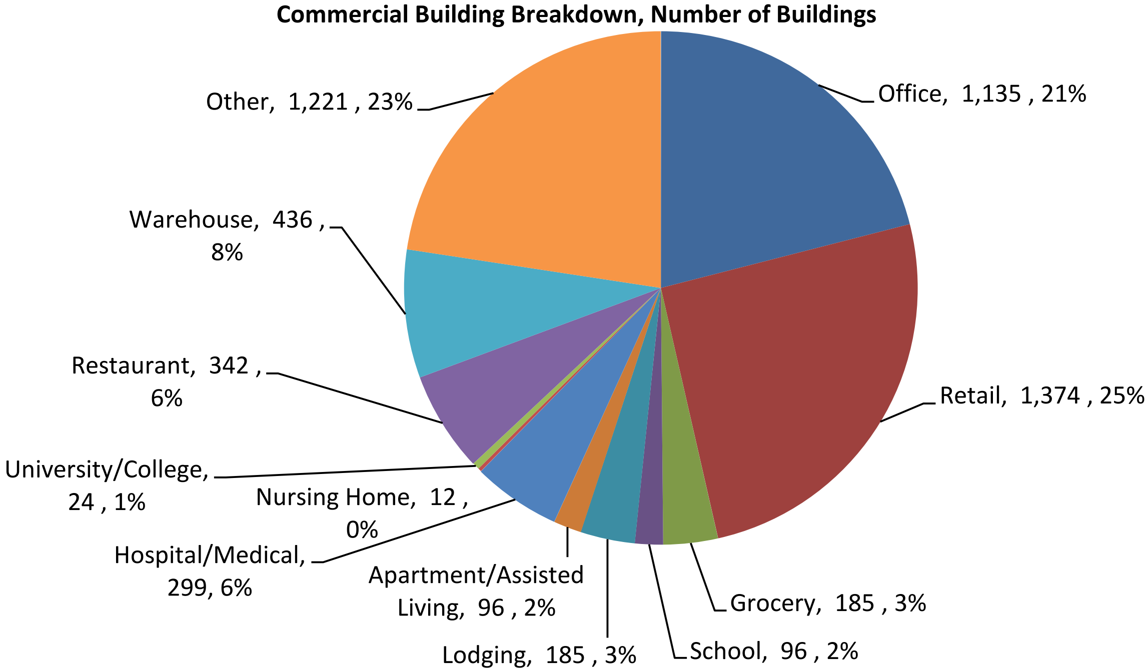


Table 19 illustrates the lighting types for commercial floor space. The percent share is of commercial square footage for each building type. Compact fluorescent lights (CFLs) are installed in up to 30 percent of commercial floor space for some building types.

Table 19
Commercial Building Lighting Characteristics

Building Type	No lighting	Linear fluorescent	Incandescent	CFL	Halogen, Quartz	High Pressure Sodium	Mercury Vapour	Metal Halide	Other
Large Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Medium Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Small Office	1%	74%	16%	7%	2%	0%	0%	0%	0%
Large Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Medium Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Small Non-Food Retail	2%	65%	9%	6%	10%	2%	0%	5%	1%
Large Hotel	1%	34%	27%	30%	6%	1%	0%	3%	0%
Medium Hotel/Motel	1%	34%	27%	30%	6%	1%	0%	3%	0%
Large School	1%	63%	23%	8%	4%	1%	0%	0%	0%
Medium School	1%	63%	23%	8%	4%	1%	0%	0%	0%
Grocery/Convenience	1%	34%	27%	30%	6%	1%	0%	3%	0%
Apartment/Assisted Living	1%	34%	27%	30%	6%	1%	0%	3%	0%
Medical	1%	63%	23%	8%	4%	1%	0%	0%	0%
Hospital	1%	63%	23%	8%	4%	1%	0%	0%	0%
Nursing Home	1%	34%	27%	30%	6%	1%	0%	3%	0%
University/College	1%	63%	23%	8%	4%	1%	0%	0%	0%
Restaurant/Tavern	1%	34%	27%	30%	6%	1%	0%	3%	0%
Warehouse/Wholesale	1%	62%	16%	4%	6%	3%	1%	9%	0%
Other	1%	74%	16%	7%	2%	0%	0%	0%	0%

Table 20 summarizes heating fuel shares among commercial buildings. Many of these buildings have more than one heating fuel and most are primarily heated by utility gas. These data are from the customer surveys completed in 2009.

Table 20
Commercial Building Heat Types

Building Type	Electricity	Natural Gas	Other	Natural Gas plus Supplemental fuel
Large Office	15%	79%	2%	81%
Medium Office	15%	79%	2%	81%
Small Office	15%	79%	2%	81%
Large Non-Food Retail	7%	81%	11%	92%
Medium Non-Food Retail	7%	81%	11%	92%
Small Non-Food Retail	7%	81%	11%	92%
Large Hotel	44%	38%	16%	54%
Medium Hotel/Motel	44%	38%	16%	54%
Large School	25%	65%	8%	73%
Medium School	25%	65%	8%	73%
Grocery/Convenience	25%	65%	8%	73%

Table 20 Commercial Building Heat Types				
Building Type	**Electricity**	**Natural Gas**	**Other**	**Natural Gas plus Supplemental fuel**
Apartment/Assisted Living	25%	65%	8%	73%
Medical	25%	65%	8%	73%
Hospital	25%	65%	8%	73%
Nursing Home	25%	65%	8%	73%
University/College	25%	65%	8%	73%
Restaurant/Tavern	25%	65%	8%	73%
Warehouse/Wholesale	26%	62%	10%	72%
Other	35%	58%	4%	62%

Energy Efficiency Measures

Several measures for each end-use were analyzed to model energy efficiency potential. Table 21 below summarizes the types of technology-based measures included in the analysis. While few categories are provided in the table, several permutations of each measure within these categories exist. In total, there are over 1,300 individual measures in the commercial sector.

Table 21 Commercial Energy Efficiency Measure Categories	
Commercial Refrigeration	Water Treatment
Grocery Store Measures	Existing Building Lighting Upgrades
Pre-Rinse Spray Valve	New Building Lighting Upgrades
Cooking	Lighting Controls
Premium HVAC Equipment	Parking Lighting
Demand Control Ventilation	LED Street Lighting
ECM Motors in Variable Air Volume HVAC Systems	Window Upgrades
Continuous Optimization HVAC	Roof Insulation Upgrades
Package Roof Top Optimization & Repair	Network PC Power Management
Municipal Wastewater Treatment	Computer Servers

Customer-Owned Renewable Energy

Solar PV on new and existing buildings is analyzed in this study. The measure data is from the BC Hydro 2007 study. Solar PV in commercial applications is generally sized at 100 kW. The Southern Interior of British Columbia has medium to high solar resources or approximately 4 $kWh/m^2/day$. The energy savings for renewable energies are reported separately from savings from energy efficiency measures. As reported in the Residential section, potential estimates for micro-hydro systems are not included.

Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. Table 22 summarizes the cost-effective achievable energy savings for each of the three scenarios by end-use.

Table 22
Commercial 20-Year Cost-Effective Achievable Energy Savings, MWh

	Scenario 1	Scenario 2	Scenario 3
Lighting	73,003	94,946	104,693
Building and Process Improvements	27,489	67,429	69,538
Computers	11,532	25,500	25,500
Municipal (Water Handling)	11,372	15,185	15,185
Total	123,396	203,060	214,915

These savings are the annual energy savings potential available in 2033. Tables 23 and 24 show the cost-effective and achievable winter and summer peak demand savings for each of the three scenarios.

Table 23
Commercial 20-Year Cost-Effective Achievable
Winter Peak Demand Savings, MW

	Scenario 1	Scenario 2	Scenario 3
Lighting	18.8	24.6	25.9
Building and Process Improvements	2.4	10.7	10.5
Computers	0.6	1.7	1.7
Municipal (Water Handling)	0.8	1.3	1.3
Total	22.7	38.3	39.3

Table 24
Commercial 20-Year Cost-Effective Achievable
Summer Peak Demand Savings, MW

	Scenario 1	Scenario 2	Scenario 3
Lighting	14.1	18.5	19.0
Building and Process Improvements	4.4	12.9	13.2
Computers	2.5	4.5	4.5
Municipal (Water Handling)	0.8	1.3	1.3
Total	21.8	37.2	38.0

Customer-Owned Renewable Energy

Cost and savings data for renewable energy measures were primarily obtained from the BC Hydro study. Technical potential is calculated assuming that 30% existing commercial buildings have appropriate installation sites and 45% of new construction buildings have appropriate installation sites. The result is that 1,600 existing buildings and 1,300 new buildings might be appropriate for commercial PV units.

Commercial PV units do not pass the TRC at current costs; however, similar to residential, a second scenario is analyzed where costs are decreased 10 percent annually over the planning period (consistent with cost decreases from the BC Hydro study). With this cost decrease schedule, Solar PV is cost effective beginning in 2030; therefore, achievable potential is ramped up from 1 percent annually to 8 percent over the remainder of the period. A total of 538 units are installed over the period 2030 through 2033. Table 25 summarizes the measure data and results of the analysis.

Table 25
Commercial Customer-Owned Renewable Energy

	Annual Generation kWh	Capital Cost	Installation Cost	Annual O&M	Life	TRC BC Ratio	Technical Potential MWh	Achievable Potential(1) MWh
Commercial PV Unit, 100 kW New and Existing Buildings	118,000	$450,465	$225,232	$6,757	20	0.19	334,089	63,476

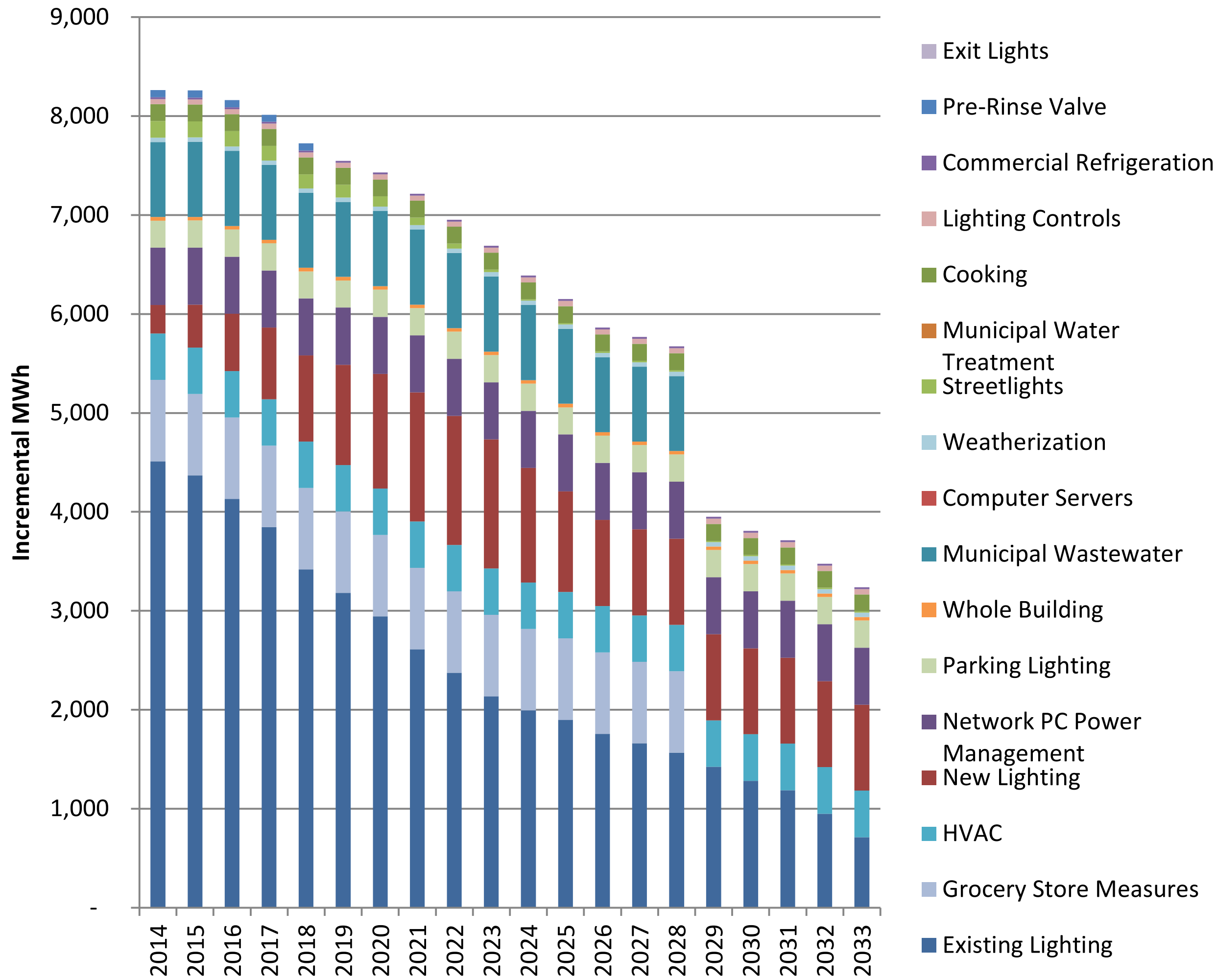
(1) Achievable Potential is economic and achievable based on decreasing cost scenario.

Program Achievable Potential

The previous section defined energy efficiency potential that is both economic and achievable through utility programs, codes, and standards. This subsection identifies potential that is both economic and achievable through utility programs only. Or, energy efficiency potential that is expected to be achieved through known code changes and product standards is not included in the following estimates.

In order to define utility program achievable potential, or “Program Achievable Potential,” ramp rates are assigned by measure category to approximate the amount of energy efficiency potential that could be reasonably obtained through utility program efforts over the planning period. Figures 23 through 25 show the Program Achievable Potential incrementally by measure category.

Figure 23
Scenario 1 ($56.61/MWh):
Commercial Program Achievable Potential by End-Use[7]



[7] Excludes savings potential achieved through codes and standards.

Figure 24
Scenario 2 ($85/MWh)
Commercial Program Achievable Potential by End-Use

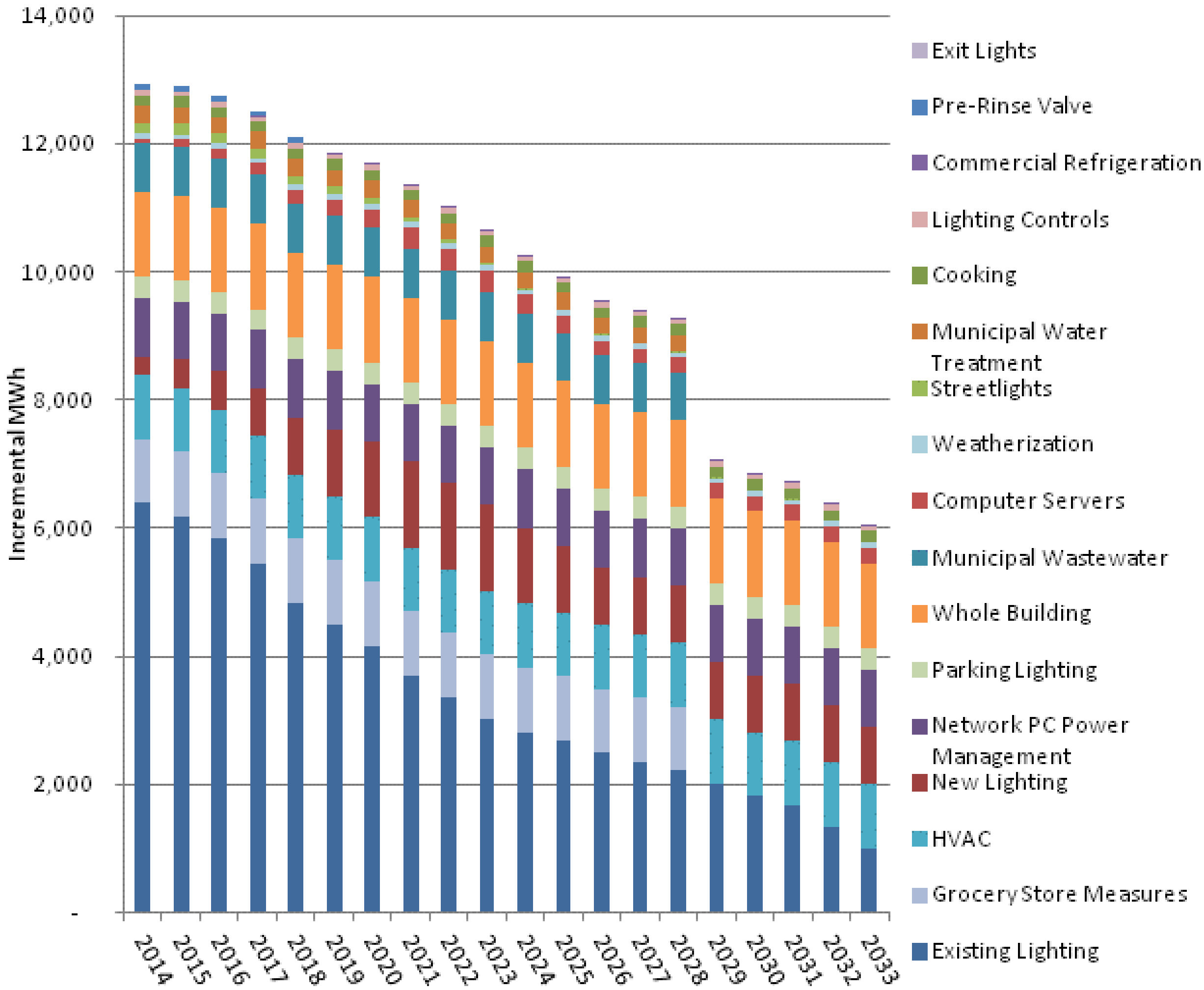
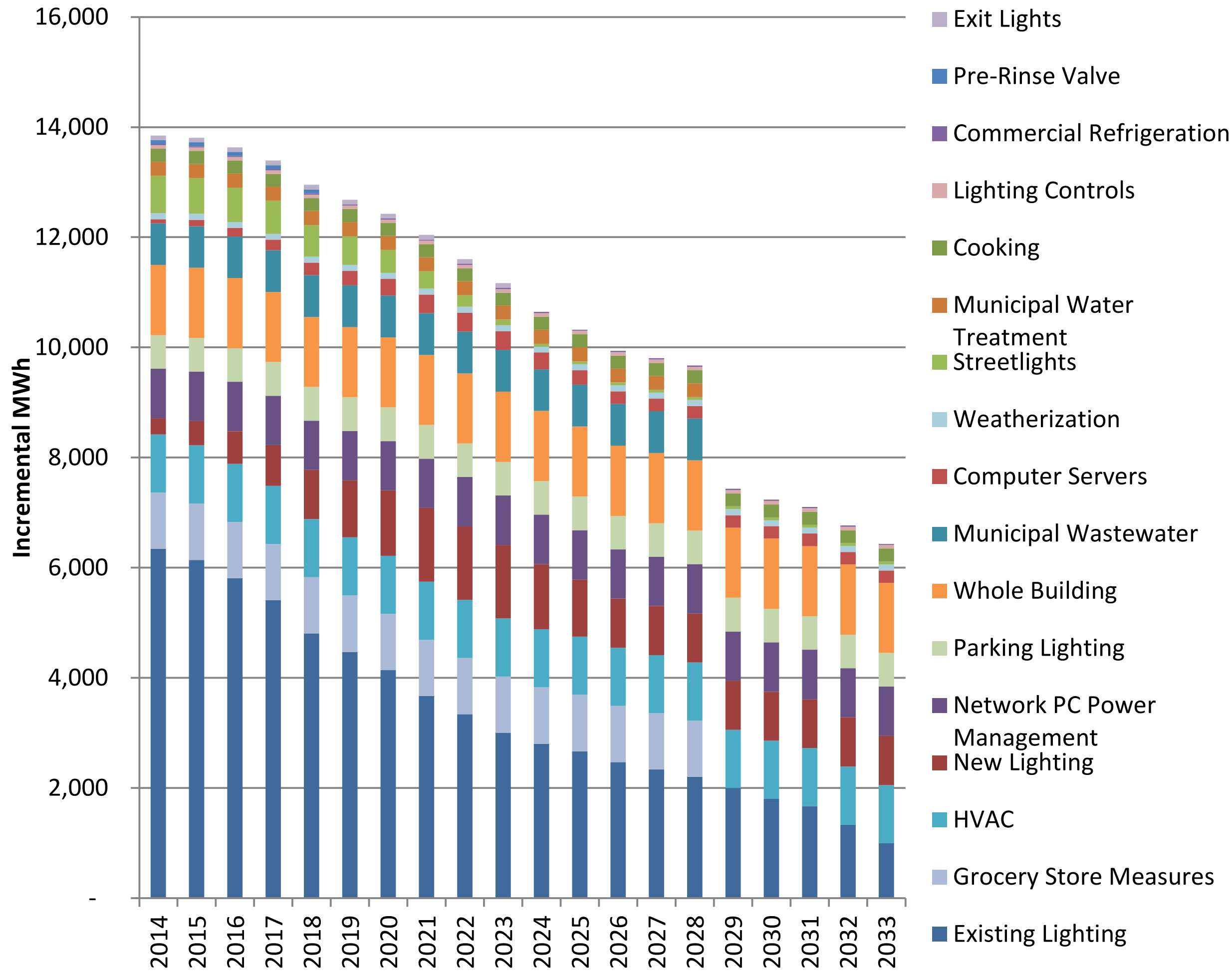


Figure 25
Scenario 3 ($128.80/MWh)
Commercial Program Achievable Potential by End-Use



Program Costs

The total utility costs are shown in Table 26 below. These costs include only the incentive and program administration costs.

Table 26
Commercial 20-Year Cost-Effective Achievable
Total Cost, $2013 ($000)

	Scenario 1	Scenario 2	Scenario 3
Lighting	$13,523	$16,267	$23,478
Building and Process Improvements	$4,790	$23,245	$27,717
Computers	$754	$7,063	$7,063
Municipal (Water Handling)	$4,539	$6,428	$6,428
Total	$23,606	$53,002	$64,685

Table 27 presents the first year utility costs for economic and achievable potential. These unit costs do not take measure life into account and include only incentives and program administration costs.

Table 27
Commercial 20-Year Cost-Effective Achievable
First Year Cost, $2013/kWh

	Scenario 1	Scenario 2	Scenario 3
Lighting	$0.16	$0.15	$0.20
Building and Process Improvements	$0.17	$0.34	$0.40
Computers	$0.07	$0.28	$0.28
Municipal (Water Handling)	$0.40	$0.42	$0.42
Total	$0.18	$0.25	$0.29

Lastly, Table 28 shows the weighted benefit-cost ratios for each of the scenarios by end-use. These weighed benefit-cost ratios are based on the economic and achievable potential which includes potential realized through codes and standards.

Table 28
Commercial Measure Weighted Benefit/Cost Ratios

	Scenario 1	Scenario 2	Scenario 3
Lighting	1.6	2.4	3.2
Building and Process Improvements	2.2	2.2	3.1
Computers	1.6	2.4	3.5
Municipal (Water Handling)	2.5	1.9	3.2
Total	1.8	2.3	3.2

Summary

Table 29 compares the energy efficiency potential estimates with the load forecast for the year 2033. The potential in the table below is both economic and achievable and does not include consumer-owned resources.

Table 29
Comparison of Load Forecast and 20-Year Economic and Achievable Potential Estimates
Commercial Sector

	Energy, MWh	Savings Percent	Winter Peak Demand, MW	Summer Peak Demand, MW
2033 Forecast	1,456,681		322.7	273.2
Scenario 1	123,396	8.5%	7.0%	8.0%
Scenario 2	203,060	13.9%	11.9%	13.6%
Scenario 3	214,915	14.8%	12.2%	13.9%

It is estimated that FortisBC could save 8.5 to 14.8 percent of 2033 commercial energy consumption with cost-effective conservation measures.

Industrial Energy Efficiency Savings Potential

Introduction

This section describes the methodology, data, and energy efficiency measures used to estimate energy efficiency potential in the industrial sector. The methodology for potential estimation is a top-down approach, rather than the bottom-up approach used in the commercial and residential sectors.

Industrial Customer Characteristics

The end-use model segments industrial load by both sector (pulp, lumber, mining, fruit packing, etc) and end-use within those sectors (fans, pump, motors, etc). Consumption within each industrial process is disaggregated by applying percentages from sources such as the BC Hydro Conservation Potential Assessment and the Northwest Power and Conservation Council. The result is a top-down methodology for classifying energy consumption by end-use.

The base year for industrial sector consumption is calculated using the 2012 energy forecast for rate schedules 30, 31, and 33 and the Tolko sawmill (wholesale customer). Five customers were removed from the industrial rate class for conservation modeling purposes: City of Kelowna, Whitewater Ski Resort, UBC Okanagan, Selkirk College, and Trail Community Health. Net energy consumption was available only. Some industrial customers are net metered; self-generation is not included in this forecast nor is it included in the FortisBC system forecast.

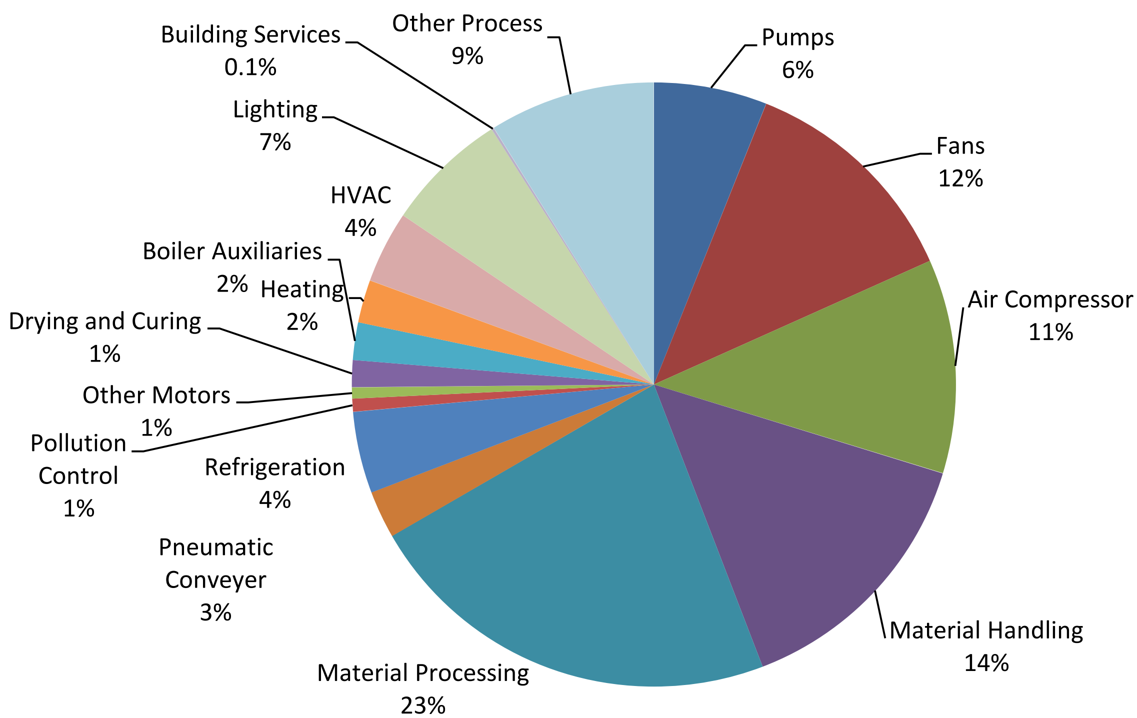
Customer consumption is grouped into classes according to the North America Industry Classification System (NAICS). Table 30 illustrates the industrial processes and annual kWh consumption for these customers. Note that the pulp load is the net conservation of a major manufacturer in the FortisBC service territory.

Table 30
Industrial Sector Consumption by Process, 2008

Industrial Process	Energy Consumption GWh
Wood products	122.6
Contractors & Construction	4.4
Mining	6.8
Fruit packers and storage	8.8
Food and Beverage	11.1
Pulp	14.5
Building Materials	57.6
Other Manufacturing/Servers	4.8
Miscellaneous	13.3
Total	244

Figure 26 shows the resulting break down of industrial electricity consumption for the base year. Total industrial consumption is 244 GWh and is expected to remain flat over the planning period. Therefore the 2033 end-use breakdown will be identical as the 2014 break-down in terms of share and total consumption.

Figure 26
Industrial End-Uses
244 GWh



Energy Benefits

The avoided cost of electricity is the dollar value per MWh, of the conserved electricity, and accounts for the benefit value in cost effectiveness tests. These energy benefits are based on the cost of a generating resource, a forecast of market prices or an integrated resource planning process.

Modeling Methodology

The methodology used to calculate industrial potential differs from the approach in the residential and commercial sectors. There are two general analytical approaches to estimating conservation potential: a bottom-up approach, utilized in the residential and commercial sectors, and a top-down approach used in the industrial sector.

The top-down approach starts with the load forecast over the study period. These load forecasts are then disaggregated by end-use. Energy savings by measure, end-use, program, or sector are then expressed as a percent of the total energy consumption. For example, pumps are a common component of manufacturing and industrial operations whose improved performance has the potential to save energy. With improved pumps, a certain percentage of the disaggregated pump load can be saved. Savings from each end-use is summed and aggregated to total potential.

Energy Efficiency Measures

There are several classes of industrial measures: cross-industry systems, industry-specific processes and whole plant optimization.

Cross-Industry

Cross-industry measures are improvements of common industrial components found in most manufacturing and industrial settings. These are widespread equipment like fans, pumps, motors, lighting, etc. Cross-industry measures are listed in Table 31 followed by a brief description of major improvements in each measure type.

Table 31
Cross-Industry Measures

Measure Type	Conservation Measure
Belts	Synchronous Belts
Compressed Air	Air Compressor Demand Reduction Air Compressor Equipment Air Compressor Optimization
Lighting	High Bay Lighting 1-Shift, 2-Shift, or 3-Shift Efficient Lighting 1-Shift, 2-Shift, or 3-Shift Lighting Controls
Motors	Motors: Rewind 20-50 HP, 51-100 HP, 101-200 HP
Fans	Efficient Centrifugal Fan Fan Energy Management Fan Equipment Upgrade Fan System Optimization
Pumps	Pump Energy Management Pump Equipment Upgrade Pump System Optimization
Transformers	Transformers-Retrofit

- **Belts** - V-Belts are commonly used to drive industrial processes. By replacing the pulley sheaves with synchronous belt pulleys and installing synchronous belts onto the end use (e.g., fans or pumps), an efficiency gain of 3%-5% can be achieved from reduced slippage and friction.[8]

- **Compressed Air** - The primary measure is retrofit of air compressors. Modern models have built-in adjustable speed drive (ASD) can achieve 40% savings over conventional fixed speed compressors. Additionally, better distribution systems and end-use improvements (use blowers in place of compressors) also contribute to savings.

- **Lighting** - In lighting, there are two main categories of measure savings: major lighting retrofits and replacement of high bay lighting. Lighting retrofits are most applicable to pulp and paper subsector and involves replacing low-efficiency mercury vapor lighting and installation of lighting control. These tend to be in large and older facilities. Replacement of high bay lighting includes changing metal halide bulbs with fluorescent T5 high-output lighting.

- **Motors** - Motors efficiency improvement is fairly straightforward and is already occurring in the FortisBC service territory. There are several difference classes of motors separated by horsepower, but each replaces standard efficiency motors with premium-efficiency motors.

- **Fans** - Savings from industrial fans come from the optimization of fan operation and retrofit with more efficient models. Operation and maintenance improvements include changing filters, maintaining belts (tension, alignment), repair duct leaks, lube bearings and maintain dampers. Additionally, fan retrofits include more efficient timers, adjustable speed drives, and low friction ducts. [9]

- **Pumps** - Pump savings come from both retrofit of pumps in addition to improved operation and maintenance of those currently in operation. New equipment includes replacement of pump at time of major repair or shutdown, proper sizing of trim impeller and control valve. Better maintenance includes coupling alignment, lubrication, seal maintenance, and vibration analysis.

Industry-Specific

Industry-specific processes are improvements of specialized manufacturing components or processes. Like cross-industry measures, it is an improvement of a single technology or process.

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[8] Northwest Power and Conservation Council. *System Optimization Measures Guide*. 6th Power Plan. March 23, 2009

[9] See id.

Common examples are refrigeration in the food service and fruit storage industries and material handling performance improvements. Cross-industry measures are show in Table 32.

Table 32
Industry-Specific Measures

Measure Industry	Conservation Measure
Hi-Tech	Clean Room: Change Filter Strategy
Hi-Tech	Clean Room: Clean Room HVAC
Hi-Tech	Clean Room: Chiller Optimize
Food Processing	Food: Cooling and Storage
Food Storage	Food: Refrigeration Storage Tune-up
Food Storage	Fruit Storage Refer Retrofit
Food Storage	CA Retrofit -- CO2 Scrub
Food Storage	CA Retrofit -- Membrane
Food Storage	Fruit Storage Tune-up
Material Handling	Material Handling2
Material Handling	Material Handling VFD2
Mining Process	Grinding Optimization, Improved Flotation Cells
Paper	Paper: Efficient Pulp Screen
Paper	Paper: Premium Fan
Paper	Paper: Material Handling
Paper	Paper: Large Material Handling
Paper	Paper: Premium Control Large Material
Wood	Wood: Replace Pneumatic Conveyor

Whole plant optimization measures are improvement of whole systems rather than discrete equipment upgrades used in cross-industry systems and industry-specific processes. This accounts for interactive effects in industrial technologies. Such measures require a much more tailored approach that includes: demand-side assessment; proper design, sizing, and/or reconfigurations to match supply to demand; system "commissioning;" sustainable O&M; and supporting management practices.[10] The savings and approach to plant optimization is categorized in a tiered system based the review of numerous case studies and regional program data: Plant Energy Management (First Tier), Energy Project Management (Second Tier), Integrated Plant Energy Management (Third Tier).

[10] Northwest Power and Conservation Council. *System Optimization Measures Guide*. 6th Power Plan. March 23, 2009

Estimating Technical Potential

The technical potential is the sum of savings from all industrial measures and each industrial sub-sector. It represents the amount of energy efficiency potential that is available regardless of cost or other constraints such as willingness to adopt measures.

Estimating the technical potential begins with determining the amount of energy consumed for each end-use (e.g. pumps, fans, motors, etc) in each industrial subsector (paper, wood, mining, etc). Data for this step was calculated in the end-use model. For example, in the wood products industry, 11% of load (13,981,482 kWh/yr) is used for drying fans. Table 33 illustrates an example of end-uses for wood manufacturing. All other industries (mining, construction, fruit packing, etc) have a different associated top-down savings percentage for each component of disaggregated load. An applicability value determines the amount of the end-use load eligible for measure savings. The applicability value is highly dependent on the measure and the industrial sector. For example, certain motors sizes are only applicable to select industries.

Table 33
End-Use Disaggregation Example, Wood Products

	Share	GWh
Drying Fans	11%	14.0
Air Compressor	13%	16.4
Material Handling	23%	28.2
Material Processing	29%	35.6
Pneumatic Conveyor	5%	6.2
Pollution Control	1%	1.2
Boiler Auxiliaries	4%	4.9
Heating	3%	3.7
HVAC	2%	2.8
Lighting	6%	7.6
Other Process	2%	2.1
Total		**122.6**

Estimating Achievable Potential

Achievable efficiency is the amount of energy savings potential that is achievable and cost-effective. To find cost-effectiveness potential, energy efficiency measures must pass economic screening. In British Columbia, economic potential is defined using a total resource cost (TRC) test to screen measures for cost effectiveness (discussed in more detail in the "Methodology" section of the report). All of the measures discussed in this section pass the TRC. Therefore the "Achievable" potential in this section means that the potential is both economic (cost-effective) and achievable. Previous conservation by FortisBC will also be addressed.

Potential Estimates

As described in the methodology section, end-use load forecast data and energy efficiency measures are combined to produce estimates of energy efficiency. Table 34 summarizes the cost-effective achievable energy savings for each of the three scenarios by end-use.

Table 34
Industrial Cost-Effective Achievable Energy Savings, MWh

	Scenario 1	Scenario 2	Scenario 3
Compressed Air	3,819	4,244	4,244
Energy Management Information Systems (EMIS)	4,342	4,824	4,824
Industrial Efficiencies	16,628	22,064	22,641
Total	24,789	31,132	31,709

These savings are the annual energy savings potential available in 2033. Tables 35 and 36 show the cost-effective and achievable winter and summer peak demand savings for each of the three scenarios.

Table 35
Industrial Cost-Effective Achievable
Winter Peak Demand Savings, MW

	Scenario 1	Scenario 2	Scenario 3
Compressed Air	0.7	0.7	0.7
Energy Management Information Systems (EMIS)	0.7	0.7	0.7
Industrial Efficiencies	3.1	3.6	4.0
Total	4.5	5.0	5.3

Table 36
Industrial Cost-Effective Achievable
Summer Peak Demand Savings, MW

	Scenario 1	Scenario 2	Scenario 3
Compressed Air	0.7	0.7	0.7
Energy Management Information Systems (EMIS)	0.7	0.7	0.7
Industrial Efficiencies	3.1	3.6	3.7
Total	4.4	4.9	5.1

Program Costs

The total utility costs are shown in Table 37 below. These costs include only the incentive and program administration costs.

Table 37 Industrial 20-Year Cost-Effective Achievable Total Cost, $2013 ($000)			
	Scenario 1	**Scenario 2**	**Scenario 3**
Compressed Air	$527	$489	$489
Energy Management Information Systems (EMIS)	$377	$350	$350
Industrial Efficiencies	$1,771	$2,661	$2,913
Total	$2,675	$3,500	$3,752

Table 38 presents the first year utility costs for economic and achievable potential. These unit costs do not take measure life into account and include only incentives and program administration costs.

Table 38 Industrial 20-Year Cost-Effective Achievable First Year Cost, $2013/kWh			
	Scenario 1	**Scenario 2**	**Scenario 3**
Compressed Air	$0.138	$0.115	$0.115
Energy Management Information Systems (EMIS)	$0.087	$0.073	$0.073
Industrial Efficiencies	$0.106	$0.121	$0.129
Total	$0.108	$0.112	$0.118

Table 39 shows the weighted benefit-cost ratios for each of the scenarios by end-use. These weighed benefit-cost ratios are based on the economic and achievable potential which includes potential realized through codes and standards.

Table 39 Industrial Measure Weighted Benefit/Cost Ratios			
	Scenario 1	**Scenario 2**	**Scenario 3**
Compressed Air	2.8	4.3	6.5
Energy Management Information Systems (EMIS)	8.7	13.1	19.9
Industrial Efficiencies	9.9	11.6	15.7
Total	8.8	10.9	15.1

Summary

Table 40 compares the energy efficiency potential estimates with the load forecast for the year 2033. The potential in the table below is both economic and achievable.

Table 40
Comparison of Load Forecast and 20-Year Economic and Achievable Potential Estimates
Industrial Sector

	Energy, MWh	Percent Savings	Winter Peak Demand, MW	Summer Peak Demand, MW
2033 Forecast	243,910		107.3	38.3
Scenario 1	24,789	10.2%	4.2%	11.6%
Scenario 2	31,132	12.8%	4.6%	12.8%
Scenario 3	31,709	13.0%	5.0%	13.3%

It is estimated that FortisBC could save 10.2 to 13.0 percent of 2033 industrial energy consumption with cost-effective conservation measures.

Irrigated Agriculture Energy Efficiency Potential

Specific industrial processes and technology are required for savings in the agricultural sector. There are three main categories of potential measures: irrigation hardware, irrigation scheduling and milk production. Currently, FortisBC has a designated rate class for irrigation consumption, all of which are direct customers. Load is not segmented for dairy production, so it is assumed that FortisBC does not have applicable dairy farms for agricultural measures. Also, irrigation scheduling measures are applicable to large field crops, while irrigation load in FortisBC is associated with fruit, apple and grape production.[11]

Therefore, improved irrigation hardware, such as the conversion to low-pressure delivery systems and improved pumps, are measures in the agricultural sector. Table 41 shows measure savings, cost and life for applicable measures from the NWPCC *6th Power Plan*. Irrigation measures are cost-effective regardless of the avoided cost forecast scenario.

Table 41
Irrigation Hardware Measures

Measure Name	Incremental Capital Cost ($/unit)	Measure Life (yr)	Savings per Applicable Acre (kWh/yr)	Applicable Acres
Convert High Pressure Center Pivot to Low Pressure System	$58	10	504	20%
Convert Medium Pressure Center Pivot to Low Pressure System	$22	10	336	15%
Pump, Nozzle & Gasket Replacement Average Well	$111	10	412	11%
Pump, Nozzle & Gasket Replacement Deep Well	$134	10	765	19%

An estimation of irrigation potential from hardware improvement is possible using a bottom-up approach as in the residential and commercial sector calculations. Irrigation consumption is 52,071 MWh/yr and remains flat over the study period. Assuming 1,400 kWh/yr for each acre, 37,193 acres of agricultural land is irrigated in the FortisBC service territory. Technical savings potential is estimated at 12,715 MWh and the achievable potential is shown in Table 42. This estimate is slightly lower than the previous CDPR.

[11] *2006 Agriculture Community Profiles: Kelowna*. Statistics Canada. www.statcan.gc.ca

Table 42 Irrigation Economic and Achievable Potential				
	2033 Achievable Potential (MWh)	**Utility Total Cost 40% Incentive 2014-2033**	**Utility Annual Cost**	**First-Year Cost $/kWh**
Irrigation	9,791	$1,080,268	$54,013	$0.11

Savings potential is estimated at approximately 20 percent of 2033 forecast consumption.

Behaviour Conservation Savings

The behavioural conservation analysis included analysis of two types of measure categories and is applied only to the residential sector. The methodology applies top-down approach where a percentage savings is applied to forecast energy consumption. The measure characteristics and savings potential are discussed below.

Behavioural Measures

The behavioural program savings and cost estimates are based two components: 1) general behavioural savings and 2) the In-Home Display (IHD) specific program. The general behavioural savings are based on a home energy reporting[12] program. For this study it was assumed that behavioural programs are 50 percent achievable, or that 50 percent of residential customers would participate and save 2 percent of energy consumption. These savings are distributed evenly over 20 years.

Savings Potential

Table 43 shows a summary of the behavioural savings. The behavior program potential is estimated as a share of applicable forecast residential energy use (after other energy efficiency potential is subtracted). Costs for behavioural programs are calculated at $30/MWh.

The IHD program estimates were developed separately and were given an emerging technology ramp rated and integrated with the general behavioural savings. In a given year, the behaviour savings value was the maximum of the general behavioural savings or the IHD measure.

Table 43
Behavioural Potential Savings Estimates

	2014	2020	2025	2030	2033	Total
Residential Load Forecast	1,831,541	1,884,924	1,946,592	2,007,940	2,044,332	38,557,876
Residential Energy Efficiency Savings	11,876	81,774	149,110	221,560	264,960	2,648,030
Net Load Forecast	1,819,666	1,803,150	1,797,482	1,786,380	1,779,373	35,909,846
Behavioural Savings	910	1,500	3,300	893	890	31,510
Cost Estimates	$27,295	$27,047	$26,962	$26,796	$26,691	$538,648

[12] O-Power, a leading purveyor of home energy reports, claims that average energy savings are approximately 2 percent per participant over the course of the year. Further, the behavioural program costs are $0.03/kWh on average.

Beginning in 2014, 910 MWh of savings could be achieved through behavioural programs for a program cost of $30/MWh. These savings are applicable to all three scenarios.

Combined CDM Potential Summary

This section combines the sector potential savings estimates for each scenario and compares the scenario potential to FortisBC's total system load forecast. Savings for customer-owned renewable energy measures are not included in this section.

Combined Program Achievable Potential

Figures 27 through 29 show program achievable potential by sector (savings from codes and standards are excluded). The behavioural savings apply to the residential sector although they are reported separately. Through energy efficiency measures, FortisBC can expect to meet 6.9 to 13.5 percent of the forecasted 2033 load depending on scenario.

Figure 27
Scenario 1 ($56.61/MWh): Program Achievable Potential by Sector

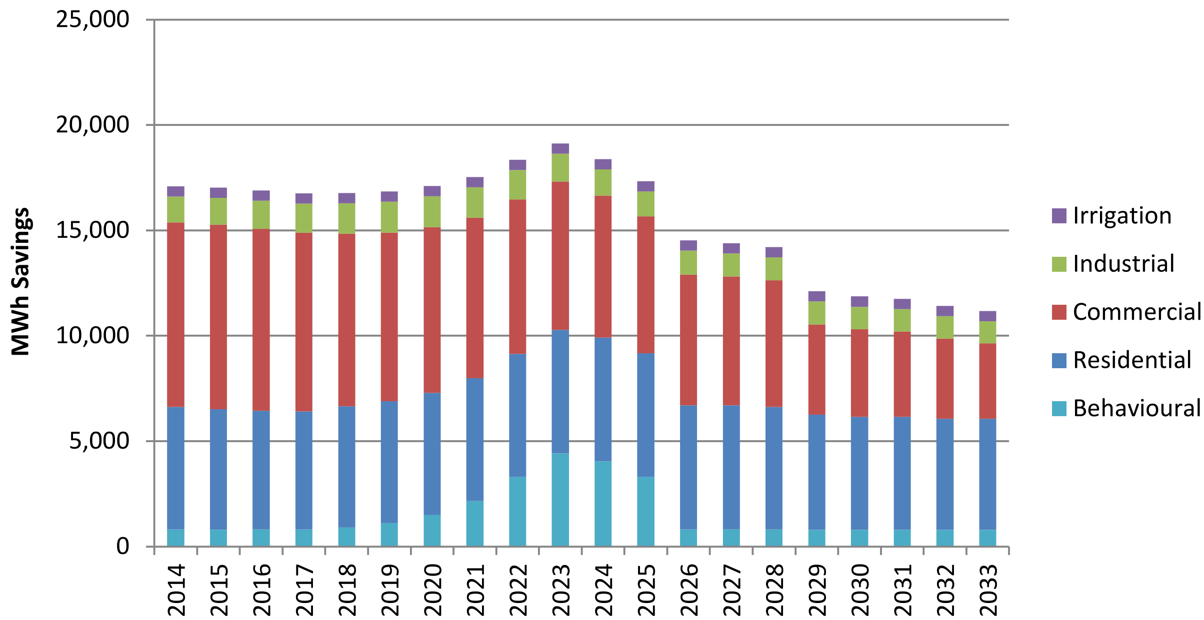

Figure 28
Scenario 2 ($84.94/MWh): Program Achievable Potential by Sector

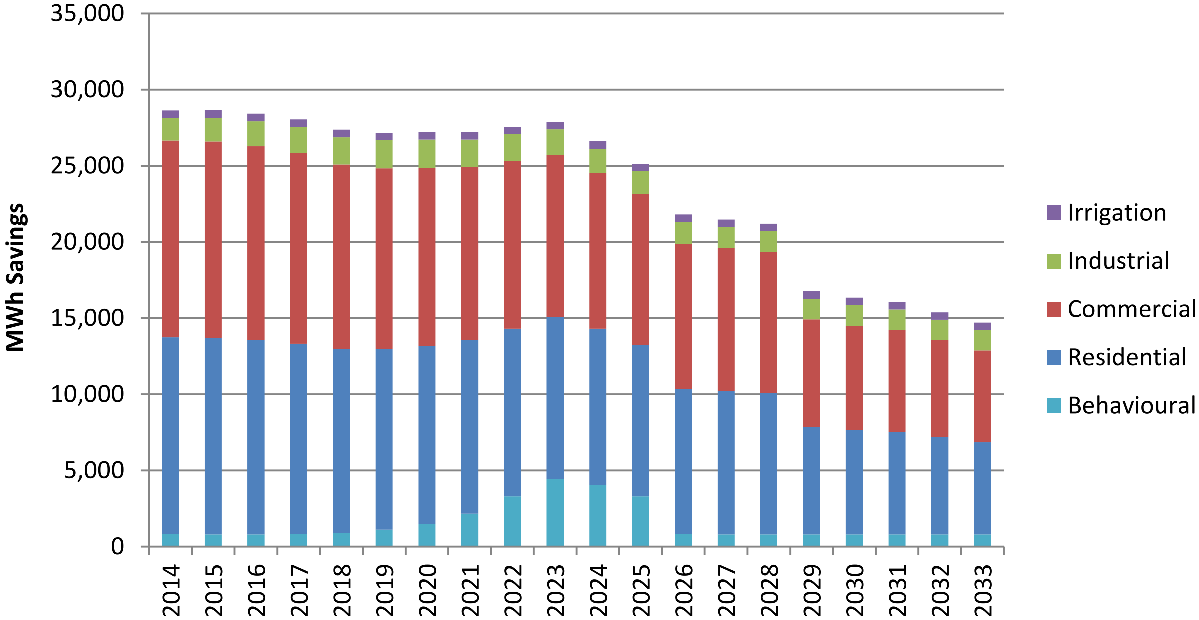

Figure 29
Scenario 3 ($128.80/MWh): Program Achievable Potential by Sector

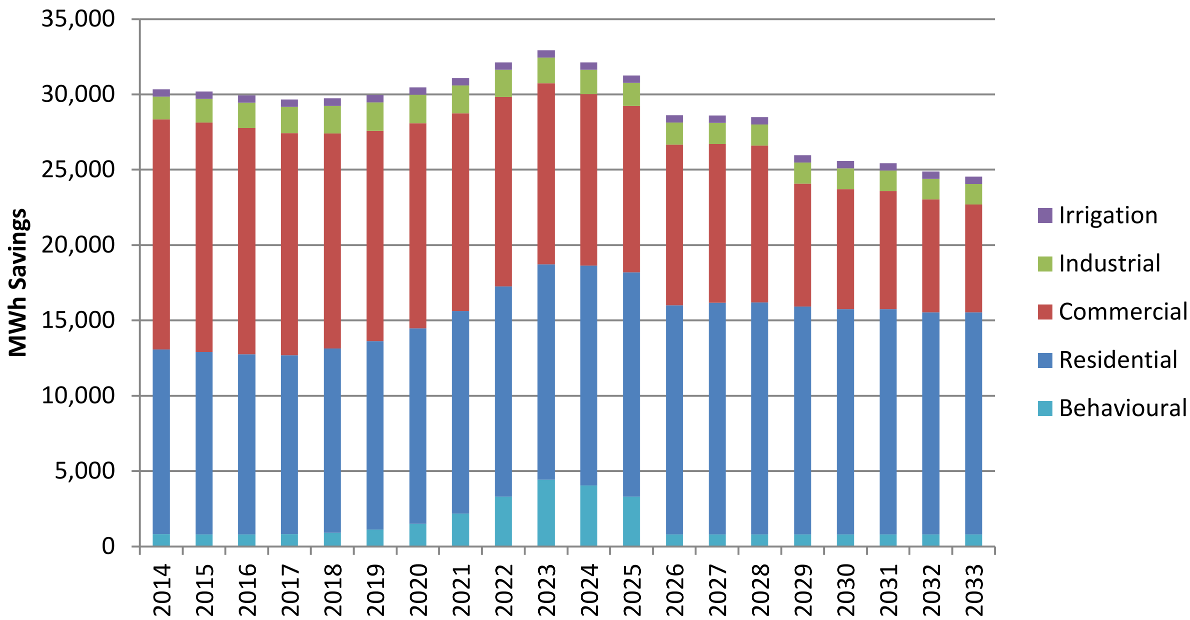

Figure 30 shows the load forecast with the three conservation potential scenarios.

Figure 30
Comparison of Load Forecast with CDPR Scenarios

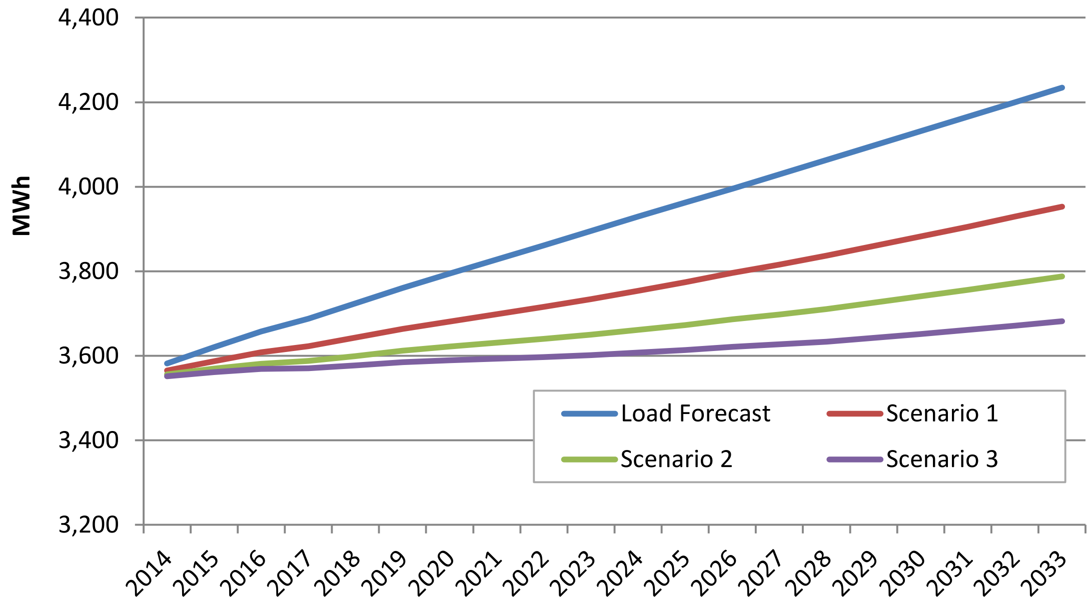

Table 44 compares the load forecasts by sector with the 2033 savings potential. The 2033 savings potential is the annual potential available by 2033 (20-year potential).

Table 44
Comparison Forecast with Energy Efficiency Potential

		Scenario 1		Scenario 2		Scenario 3	
	2033 Load MWh	2033 Savings MWh	Percent of 2033 Load	2033 Savings MWh	Percent of 2033 Load	2033 Savings MWh	Percent of 2033 Load
Residential[1]	2,056,385	114,382	5.6%	204,208	9.9%	278,312	13.5%
Commercial	1,456,681	132,099	9.1%	201,056	13.8%	232,441	16.0%
Industrial	333,766	24,789	7.4%	31,132	9.3%	31,709	9.5%
Irrigation	52,071	9,791	18.8%	9,791	18.8%	9,791	18.8%
Total System	**4,234,209**	**281,061**	**6.6%**	**446,186**	**10.5%**	**552,253**	**13.0%**

1. Savings potential includes behavioural program potential.

For comparison, the 2010 CDPR resulted in 585 GWh of program achievable potential. In the interim FortisBC has recorded 97.2 GWh of program savings, for 2010-12 inclusive.

Figure 31 illustrates the potential given in the table above. The majority of the potential is from the residential sector, which is not surprising since residential customers contribute to over half of FortisBC's retail load.

Figure 31
Scenario Comparison
2033 Potential by Sector, Annual GWh

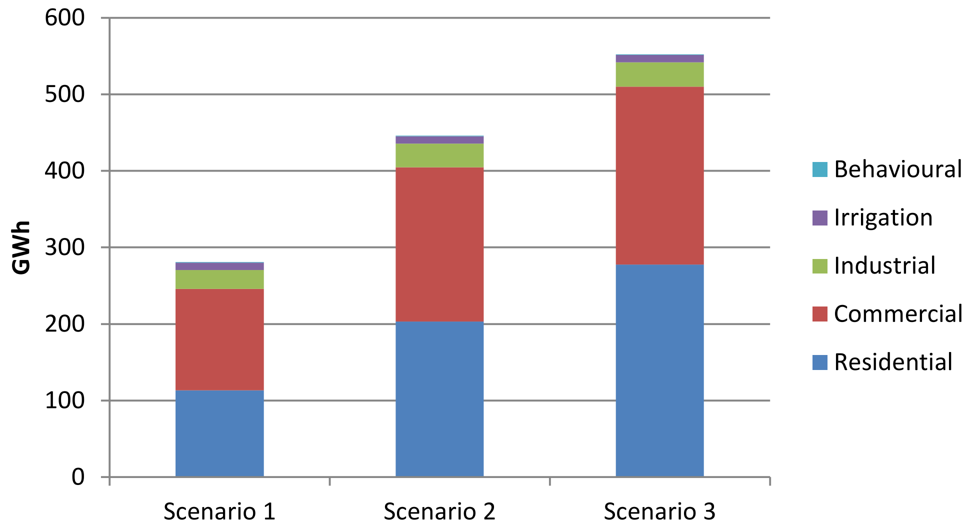

Table 45 summarizes the weighted TRC benefit-cost ratios for each sector. For the most part, the lower avoided costs are associated with lower benefit-cost ratios. Both the avoided cost and the mix of measures that are cost effective affect the weighted benefit-cost ratios.

Table 45
Weighted Benefit-Cost Ratios

	Scenario 1	Scenario 2	Scenario 3
Residential[1]	3.5	2.9	4.6
Commercial	1.8	2.3	3.2
Industrial	8.8	10.9	15.1
Irrigation	3.3	5.0	7.6
Total	3.2	3.2	4.7

1. Assumes behavioral measures benefit-cost ratios are equal to the average benefit-cost ratio for the rest of the residential sector measures.

FortisBC Naturally Occurring Conservation

Naturally occurring conservation refers to the amount of conservation that would be achieved in absence of utility programs. This includes:

1. Efficiency gains from the turnover of older equipment to current standard equipment (with higher efficiency);
2. The adoption of high-efficiency equipment due to natural market forces; and
3. Market effects that include national or provincial government programs, past utility programs or marketing efforts, or equipment vendor efforts.
4. Conservation rate structures encouraging investment.

With regard to the FortisBC conservation potential assessment, the amount of naturally occurring conservation is accounted for in two ways. The first is in the load forecast. Since the end-use load forecast was calibrated to the system forecast, in includes a basic level of naturally occurring conservation, based on past experience. Second, some of the energy efficiency measure savings values are adjusted for market saturation and turnover rates for equipment that is naturally replaced over the planning period.

While it is difficult to quantify naturally occurring conservation, a few organizations have attempted it. The published data indicate that a range of between 6 and 10 percent of achievable potential is naturally occurring. For FortisBC, this amounts to approximately 1.2 percent of 2033 load.

Given the assumption that naturally occurring conservation is 1.2 percent of 2033 load, FortisBC might expect to meet 39 to 79 percent of load growth with DSM resources through 2033 depending on scenario. Table 46 summarizes an example calculation assuming that naturally occurring conservation is 8 percent of 2033 program achievable potential.

Table 46
Naturally Occurring Conservation and Load Growth

	Scenario 1	Scenario 2	Scenario 3	*formula*
Total Program Achievable, MWh	281,061	446,186	552,253	*a*
Naturally Occurring Conservation (NOC), MWh	22,485	35,695	44,180	*b= 8% × a*
Net Program Achievable, MWh	258,576	423,701	529,768	*c = a - b*
2033 Load, MWh	4,234,209	4,234,209	4,234,209	*d*
2014 Load, MWh	3,582,055	3,582,055	3,582,055	*e*
2033 Load less NOC, MWh	4,210,783	4,211,724	4,190,029	*f = d - b*
Load growth less NOC, MWh	629,669	616,459	607,974	*g = f-e*
Load Growth Met with Net Program Potential	41%	69%	87%	*h = g ÷ c*

Summary

The conservation and demand potential review showed that a significant amount of conservation savings potential is available in FortisBC's service territory. Three scenarios were presented and the results of each scenario showed that lower levels of conservation resources are available compared to the 2010 CDPR. The revised baseline conditions, especially the much lower avoided cost, have resulted in lower overall conservation potential estimates compared with the previous assessment. Other changes, such as new lighting standards, have been implemented resulting in reduced program potential, but will still be achieved as a result of the standard (i.e., no cost to the utility).

In order to maintain recent levels of achievement, the adoption rates (i.e., ramp rates) were adjusted to essentially pull forward potential from future years, especially in the commercial sector.

Consistent with the FortisBC load forecasts, there is significantly more potential in the residential sector than in the commercial sector over the 20-year planning horizon. Therefore, in order to maintain consistency in the overall achievements, the residential portion will need to increase as the commercial portion will likely decrease.

Finally, it is recommended that FortisBC continue to update the CDPR with customer characteristic data, forecasted loads, new measures or measure data, codes and standards, and historic achievement.

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Appendix A
Cost-Effectiveness in British Columbia

Introduction

The British Columbia Ministry of Energy, Mines and Petroleum Resources ("Ministry") amended the Public Utilities Commission Act (Bill 15-2008) to require public utilities to estimate cost-effective demand side resources (DSM) as part of their long term resource plan and to provide a plan to acquire those resources as a first priority over supply-side options. This memo summarizes how the Ministry expects utilities to estimate cost-effectiveness.

Long-Term Resource Plan

Section 44.1, Long-term resource and conservation planning, of the Public Utilities Act[13] requires that a public utility's Long-Term Resource Plan (LTAP) must include all the following:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures; and

(g) any other information required by the commission.

[13] Utilities Commission Act [RSBC 1996] Chapter 473. Current to September 9, 2009 available online at: http://www.bclaws.ca/Recon/document/freeside/--%20U%20--/Utilities%20Commission%20Act%20%20RSBC%201996%20%20c.%20473/00_96473_01.xml#section44.1

Demand-Side Resources

Cost-effective measures to be examined include rate, measure, action or program measures. The DSM evaluations must be approved by the British Columbia Utilities Commission (BCUC). In order for the BCUC to consider a portfolio of DSM programs complete, that portfolio must include:

- *Low-Income Programs* – Low-income households are defined by Statistics Canada's Low-Income Cut-Offs (LICO) for a particular year
- *Rental Programs* – Programs may target either tenant and or landlord. The focus must be on the accommodation rather than the residents (emphasis on technology).
- *Education Programs* – Includes funding of the development of education program regarding energy efficiency and conservation.
- *Post-Secondary Programs* – Includes funding of programs such as the integration of energy efficiency into a business or MBA program curriculum and trades training.

Cost-Effectiveness

The cost effectiveness of each measure may be calculated either at the individual level, in a bundle with other measures, or at a portfolio level.

Low-Income

Low income DSM programs have additional benefits that are not accounted for in energy savings such as fewer shutoff/reconnect costs, fewer rearranges, and less bad debt to be written off. Therefore, 30 percent in additional benefit is to be added to low income program measure cost-effectiveness tests.

Specified DSM and Technology Innovation

- Specified DSM includes the following measures:
  - Education
  - Funding energy efficiency training for manufacturers, sellers, installation tradesmen, brokers, managers of energy efficiency products and buildings.
  - Community engagement programs that assist, cooperate or directly increase stakeholders' awareness of energy efficiency. Stakeholders include first nation, government, or non-profit groups.
- Technology innovation programs including market transformation.

These measures will be evaluated in a group with other measures or as a portfolio to help support the expenditures. The reasoning behind the grouping of measures for the purpose of cost-effectiveness tests is that these measures are supportive and long term rather than immediate or standalone.

Total Resource Cost

Avoided Cost

Bulk electricity purchasers from BC Hydro must use BC Hydro's long-term marginal cost rather than the purchase price of power. This avoided cost requirement for bulk purchasers increases the amount of DSM that is cost-effective.

Summary

It appears the British Columbia does not require specific total resource costs and benefits be included in the benefit-cost analysis. In their 2007 study, BC Hydro uses avoided transmission and avoided power costs to evaluate measure cost-effectiveness. BC Hydro escalated their avoided power costs (energy) by 50%. Measure costs are either full or incremental capital costs.

Appendix B
Cost-Effectiveness Tests

Two general screening methods can be used to rank demand and supply options. These are benefit-to-cost ratios and levelized cost. A benefit-to-cost ratio divides resource benefits by resource costs to calculate a ratio. If the ratio is greater than one, the resource is cost-effective; if the ratio is less than one, the resource is not. Levelized costs sum the fixed and variable costs of a resource over its life, taking into account the time value of money, and divide them by the associated output or savings. A cost per unit of output or savings is developed and is usually expressed in a constant dollar year. This levelized cost can then be compared with a fixed generating resource or power contract to determine cost effectiveness.

Several different economic tests are available for evaluating resource options. All of the tests incorporate benefit-to-cost analyses. However, the perspective from which the costs and benefits are evaluated differs among the tests. The five tests are the total resource cost (TRC) test, ratepayer impact measure (RIM) test, participant test, utility cost test, and societal test. The tests are used primarily to evaluate DSM resources.

The TRC is most commonly used as the primary cost test to determine cost effectiveness of DSM options. Using the TRC benefit cost ratio, all DSM measures can be compared with available supply resources. Other tests can then be applied to determine the cost effectiveness from the various perspectives (e.g., utility, ratepayer).

Cost and Benefit Components

Changes in Supply Costs. One of the main benefits of a DSM option is its associated reduction in supply costs. This can occur as a result of a decrease in energy use or as a result of a shift of energy from a more expensive period to a less expensive period. The avoided supply cost is calculated by multiplying the reduction in total net generation by the marginal cost. If energy has been shifted instead of reduced, the resulting increase has to be included on the cost side. The changes in supply cost for periods where energy use increases are costs (increased supply cost), and the changes in supply costs for periods where energy use decreases are benefits (avoided supply cost).

Changes in Revenue and Bills. Another large effect of DSM programs is revenue reduction. Lost revenues are a cost to the utility and tend to increase rates on a per-unit basis. On the other hand, DSM program participants receive equivalent benefits, because their consumption is reduced.

Utility Costs. This category includes all costs of planning, implementing and evaluating a DSM program, except for incentives paid directly to the participant. Also included are those for marketing, administrative, equipment and program monitoring and evaluation.

Participant Costs and Avoided Participant Costs. Participant costs include all out-of-pocket expenses that a participant incurs as a result of participating in the program. These costs are calculated before the participant receives any rebate or incentive payment. If the participant avoids some cost by participating, it is considered a benefit to the participant.

Incentives and Participation Charges. Incentives are any dollar amount that the utility pays directly to the participant. These include rebates, bill reductions, rate discounts and below-market loans. The incentive that a utility pays a dealer or builder is a utility cost unless the incentive is passed through to the participants. A participation charge is the payment by the participant to the utility related to a DSM program.

Tax Credits and Payments by Third Parties. If the participant receives any tax credit for participating, it is accounted for in this benefit category. Any payment made to the participant by a non-utility source (e.g., a manufacturer's rebate) also falls under this account.

Externalities. This category includes any costs or benefits that are external to standard cost-accounting methods. Externalities include effects, both positive and negative, to society.

Overview of the Tests

This section briefly describes the five most commonly used cost-effectiveness tests. Each test represents a different perspective in determining the cost-effectiveness of a program.

Total Resource Cost Test. The TRC test is a measure of the total net expenditures of a DSM program from the perspective of the utility and its ratepayers. The benefits are avoided supply costs, net avoided participant costs and tax credits. The costs include increased supply, net participant costs and utility costs. Since the utility and its ratepayers are considered together by this method, transfer payments between the two are ignored. This test is a measure of the change in the average cost of energy services. The following formula explains the relationships within the TRC method.

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t + PAC_t *}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{UC_t + PC*_t + UIC_t}{(1+d)^{t-1}}$$

* Participant costs and participant avoided costs in this test are net of free riders.

Utility Cost Test. The utility cost test is a measure of the changes in total costs to the utility from a DSM program. It evaluates the DSM program from the perspective of a utility's total cost. The benefit component is avoided supply costs. The cost components are increased supply costs, incentives, and utility program costs. The test measures the change in the average energy bills across all customers.

The utility cost test is identical to the RIM test, except that the utility's revenue losses are not included as a cost input in the utility cost test, and revenue gains from increased sales are not included as a benefit. The following formula describes the utility cost test calculations.

$$B_{UC} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$C_{UC} = \sum_{t=1}^{N} \frac{UC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

Participant Test. The participant test measures the quantifiable benefits and costs to the customer as a result of program participation. Benefits include reductions in customers' utility bills, avoided customer costs, incentives and tax credits. Participant costs include any customer out-of-pocket expenses resulting from participation. The test is a measure for the average customer and ignores free riders. The participant test provides a good indication of the attractiveness of the program to the average non-free rider expected to participate. The participant test calculation is based on the calculation that follows.

$$B_p = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t + PAC_t}{(1+d)^{t-1}}$$

$$C_p = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Societal Test. A common variation on the total resource cost test is the societal test. It measures the benefits and costs to all of society (i.e., including other utilities, government agencies, and citizens outside the jurisdiction). The societal test differs from the total resource cost test in three ways. First, a societal discount rate is used to place value on all future benefits and costs, reflecting society's low-risk view of future investments. Second, environmental externalities are included in the benefit-to-cost equations. Third, this test excludes tax credits because they are transfer payments within society. The mathematical equations for the societal test follow.

$$B_S = \sum_{t=1}^{N} \frac{UAC_t + PAC*_t + EB_t}{(1+s)^{t-1}}$$

$$C_S = \sum_{t=1}^{N} \frac{UC_t + PC*_t + UIC_t + EC_t}{(1+s)^{t-1}}$$

* Participant costs and participant avoided costs in this test are net of free riders.

Ratepayer Impact Measure Test. The ratepayer impact measure (RIM) test quantifies the impacts on customers' rates resulting from changing utility revenues and operating costs. It assumes that DSM reduces utility revenues and increases costs and that customer rates must be increased to balance the utility's books.

Benefits considered by the RIM test are avoided supply costs and revenue gains. Costs for the RIM test are increased supply costs, utility program administration, incentives and reduced revenues from energy savings. The calculation of the RIM test is as follows.

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+r)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + UC_t + INC_t}{(1+r)^{t-1}}$$

Glossary of Symbols

B_P	Benefit to participants (participants test)
B_{RIM}	Benefits to rate levels or customer bills (ratepayer impact measure test)
BI_t	Bill increases in year t
BR_t	Bill reduction in year t
B_S	Benefits of the program (societal test)
B_{TRC}	Benefits of the program (total resource cost test)
B_{UC}	Benefits of the program (utility cost test)
C_P	Costs to participants (participants test)
C_{RIM}	Costs to rate levels or customer bills (ratepayer impact measure test)
C_S	Cost of the program (societal test)
C_{TRC}	Costs of the program (total resource cost test)
C_{UC}	Costs of the program (utility cost test)
d	Discount rate
EB_t	External benefits to society due to the program in year t
EC_t	External costs to society due to the program in year t

INC_t	Incentives paid to the participant by the sponsoring utility in year t
PAC_t	Participant avoided costs in year t
PC_t	Participant costs in year t
r	Return on investment
RG_t	Revenue gains from increased sales in year t
RL_t	Revenue loss from reduced sales in year t
s	Societal discount rate
TC_t	Tax credits in year t
UAC_t	Utility avoided supply costs in year t
UC_t	Utility program costs in year t
UIC_t	Utility increased supply costs in year t

For additional information regarding these and other cost effectiveness test, refer to the California Standard Practice Manual.[14]

[14] California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. July 2002. http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf

Appendix C
Ramp Rates

Table C-1
Ramp Rates

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
10YearEven	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12YearEven	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	8.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15YearEven	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%
20YearEven	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
EmergTech	1.0%	1.3%	1.5%	1.8%	2.0%	2.5%	3.3%	4.1%	5.0%	5.5%	6.0%	6.5%	7.0%	7.3%	7.7%	7.9%	8.0%	8.0%	8.0%	8.0%
10YearEven	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
15YearEven	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%
20YearEven	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
5YearEven	20.0%	20.0%	20.0%	20.0%	20.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
ResLight	8%	7%	6%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	4%	4%	4%	4%
Electronics	1%	1%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
EnerGuide80	5%	5%	5%	5%	5%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
EnerGuide90	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
New Lighting - Program	1.0%	1.5%	2.0%	2.5%	3.0%	3.5%	4.0%	4.5%	4.5%	4.5%	4.0%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
New Lighting - Code Change	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
HVAC - Code Change	5.5%	5.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	3.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Accelerated 10-year	13.0%	12.5%	12.0%	11.5%	11.0%	10.0%	8.0%	6.0%	4.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
20YearDeclining	9.5%	9.2%	8.7%	8.1%	7.2%	6.7%	6.2%	5.5%	5.0%	4.5%	4.2%	4.0%	3.7%	3.5%	3.3%	3.0%	2.7%	2.5%	2.0%	1.5%

Attachment 248.12

DSM ADVISORY COMMITTEE

TERMS OF REFERENCE

Sept 2008

Purpose

The purpose of the DSM Advisory Committee is:

- To review the effectiveness of the DSM incentive mechanism employed by FortisBC to report DSM performance, and to revise its structure as required, from time to time;
- To review DSM operating results for incentive calculation purposes;
- To provide advice and comment to FortisBC on programs, targets and the semi-annual DSM operating results;
- To provide advice and comment to FortisBC on energy efficiency potential studies, business plan preparation, capital plan, program design strategies, and program evaluation studies; and
- To report the Committee's activities and its comments on the incentive calculation to an annual review process before the BC Utilities Commission.

FortisBC shall endeavor to seek consensus to the greatest extent possible on all DSM Advisory Committee recommendations made to the BCUC regarding the annual DSM performance.

Membership

The Committee comprises FortisBC staff, customers and/or customer interest groups, and businesses or associations with a direct interest in DSM in the FortisBC service territory.

The non-FortisBC members shall be comprised of:

- A minimum of four members representing customers and/or customer interest groups from a variety of customer classes, including wholesale, residential, general service and industrial,
- A maximum of two members representing businesses or associations,
- Members from all regions of the Company's service area, specifically the South Okanagan-Similkameen, Kelowna, and the West Kootenay-Boundary,
- BC Utilities Commission and Ministry of Energy, Mines, and Petroleum Resources staff who serve *ex officio*.

Members of the Committee may nominate candidates for membership from time to time as vacancies occur. New members must be accepted by a majority of members and FortisBC.

Term of Service

A term of service is two years from first appointment, with one renewal term. Members may serve additional terms with the approval of a majority of members and FortisBC.

Meetings

Electronic formats such as video conferencing, telephone conferencing, and email may be employed, in addition to face-to-face meetings. Notes shall be taken at committee meetings and circulated on a timely basis.

Activities

The DSM Advisory Committee will be involved directly in the DSM Incentive Mechanism development, design, or revision.

1. The DSM Advisory Committee will review FortisBC' Semi-Annual DSM reports that are prepared for filing with the BCUC in order to assess the DSM performance and calculate the annual incentive amount earned by the Company.

2. The DSM Advisory Committee will review planned spending and savings targets and estimated incentive amount for the following year, prior to delivering the annual performance report to the BCUC.

Schedule Example

Schedule	Deliverable	Committee Role
Annual	- December 31 Semi-Annual DSM report or projections	Review, comment prior to Annual Review and filing with BCUC
	- Performance Incentive Calculation	Review, comment on performance, acceptances for the Annual Review
	- Committee report to Annual Review	List committee activities, contributions, and accomplishments for the year, and planned activities for the next year; endorse incentive calculation
Third Quarter	Annual plan implementation progress, and program development	Comment, input, participation
	June 30 Semi-Annual DSM report	Review, comment prior to filing with BCUC
As Required	Capital plans, operating plans, program design, scope for studies, draft reports, policy	Review, comment, input, and advise
	DSM Incentive Mechanism	Review, study, revise, and recommend

Other Items

In fulfilling its purpose the DSM Advisory Committee shall take into account the following conditions related to FortisBC demand-side management efforts:

- The DSM portfolio of programs must have a cumulative benefit cost ratio that is greater than one, and individual projects must pass this test before full allocation of overhead costs;
- Benefits are defined as avoided power purchase costs and the value of deferred capital expenditures and,
- Annual budgets and annual targets are determined on a reasonable effort basis.

APPENDIX

DSM Incentive Committee Background

In 1996 the BC Utilities Commission asked for performance reporting from several operating areas of the Company, in conjunction with the settlement agreement for a revenue requirement application. Industry-wide measures and criteria for electric utilities, such as Customer Average Interruption Duration Index (CAIDI), were well established, but the same was not true for the performance measurement of utility demand-side management resources. In order to establish appropriate criteria to measure DSM performance, FortisBC invited interested participants in the Negotiated Settlement Process (NSP) for the Application to form a DSM Incentive Committee.

The Demand-Side Management Incentive Committee was established in 1997/98 and began work with FortisBC to determine the appropriate performance measures and incentive mechanism that could be applied to DSM annual results. In 1999 the Tellus Institute assisted FortisBC and the Committee members to devise the shared savings mechanism (SSM), whereby an incentive is provided to the Company as it meets formula target levels set at the beginning of each year.

The SSM continues to be refined to address issues such as economic downturn in the service area and utility program overspending.[1] The role of the Committee expanded over the years with the members reviewing draft reports; study terms of reference, conclusions, and action plans, prior to filing with the BCUC. These included the *2003 DSM Review*, the *2005 Energy Efficiency Potential Update*, and the *2005 PowerSense Five-Year Business Plan*.

Over the same period, demand-side management performance reporting became a requirement of either a Revenue Requirement Application or an Annual Review under a Negotiated Settlement Process. To recognize the need for the Committee's continued involvement and the permanent performance reporting requirement, in 2006 the BC Utilities Commission approved FortisBC's request that the Incentive Committee be renamed the DSM Advisory Committee.

[1] Economic risk adjustment factors for savings targets were considered, and, to address overspending, annual expenditures were capped at 110% of planned expenditures for incentive calculation purposes