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June 30, 2011

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, BC
V6E 2N7

Attention: Mr. James L. Quail, Executive Director

Dear Mr. Quail:

Re: FortisBC Energy Utilities ("FEU") 2012 and 2013 Revenue Requirements and Natural Gas Rates Application

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners Organization et al ("BCOAPO") Information Request ("IR") No. 1

On May 4, 2011, the FEU filed the Application as referenced above. In accordance with Commission Order No. G-81-11 setting out the Regulatory Timetable for the review of the Application, and further amended by Commission Letter No. L-45-11, the FEU respectfully submit the attached response to BCOAPO IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Alanna Gillis, Acting Commission Secretary
Registered Parties

1.0 Reference: Executive Summary and Introduction, page 3

Work-in-progress and deferral Account Balances included in Rate Base

1.1 Please explain the conditions under which work-in-progress would not attract AFUDC.

Response:

Work-in-progress would not attract AFUDC if either the project costs are not expected to exceed $50 thousand or if the duration of the project is expected to be less than three months.

1.2 Is the AFUDC equal to the WACC, pre-tax or post-tax?

Response:

The AFUDC is equal to the WACC post-tax.

Please refer to BCUC IR 1.87.1 for a discussion on the supporting calculations for the AFUDC and WACC rates.

1.3 Are all unamortized deferral accounts always considered to form part of rate base? If so, please explain why.

Response:

No, there are two types of deferral accounts – rate base and non-rate base. In the FEU's case, the majority of deferrals are rate base deferrals with the mid-year balance included in the rate base calculation for the utility. Please see BCOAPO IR 1.1.4 for a further discussion of rate base and non-rate base deferral accounts.

For a list of the non-rate base deferrals, please refer to Appendix G of this Application (Exhibit B-1).

1.4 Please explain the principles underpinning whether amounts should attract (i) a rate base rate of return, (ii) an AFUDC (if different from return on rate base), (iii) a carrying charge based on long-term debt rates, or (iv) a carrying charge based on short-term debt rates.

Response:

Each of these alternatives is discussed below.

i. Rate Base Rate of Return

A utility's Rate Base is used to calculate the Earned Return. The Earned Return in a regulatory process is the return required to pay for the company's debt interest and provide a fair rate of return on the equity invested by the shareholder(s) of the company. In British Columbia the Rate Base is primarily composed of the original depreciated cost of the gas plant in service plus average forecast investment in new plant additions, deferred costs and credits, and working capital. Therefore, if an amount is approved to be included in rate base it will attract the rate base rate of return.

ii. AFUDC

For FEI the AFUDC rate is the return on rate base adjusted by having the cost of debt calculated based on an after-tax cost. AFUDC is generally applied to Construction Work-in-Progress ("CWIP") projects which exceed $50 thousand or three months in duration. AFUDC is also applied, subject to Commission approval, to non-rate base deferral accounts. The recommendation for a rate base deferral account as compared to a non-rate base deferral account has primarily been one of timing, or as a means to stream cost recovery to a particular customer or group of customers separate from all other customers. In the case of a timing issue, if the Companies are able to forecast balances for deferral accounts and include them in revenue requirements, then that is the preferred treatment. In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, that deferral account will be non-rate base attracting AFUDC until such time as rates are re-set under the next revenue requirements process, and the account is rolled into rate base. In these instances where AFUDC is being charged, the CWIP or deferral is not included in the utility's rate base, as the AFUDC is the earned return that compensates the utility investors, both debt and equity.

AFUDC is provided for in the BCUC Uniform Code of Accounts. The following description is given on when and how AFUDC is to be applied:

"This account shall include the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used. The amount capitalized shall be charged to this account and concurrently credited to account No. 324], "Allowance for Funds Used During Construction".

The rate applied must receive prior approval of the Commission. When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation, or ready for service, shall be treated as "Utility Plant in Service" and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service".

Permission to apply AFUDC was first approved by the Commission in FEI's (formerly BC Gas Inc.) 1992 test year Revenue Requirement Application and has been applied since then.

iii. <u>A Carrying Charge Based on Long-term Debt Rates</u>

FEU does not use a carrying charge based only on Long Term Debt. Using such a rate would be unusual and possibly only applicable in special circumstances whereby the Commission might direct its use for a particular project or a new deferred charge.

iv. <u>A Carrying Charge Based on Short-term Debt Rates</u>

There are some components of the rate base and cost of service that have an effect on short-term working capital. Since short-term working capital should be financed by short-term debt; the use of the short-term debt rate is applied in those circumstances. The use of short-term bank cost is applied to customer security deposits, and to the variance in the forecast deferral and actual deferred cost for RSAM, RSDA, CCRA and MCRA. The short-term debt rate is also applied to the variance in the forecast average cost of gas in storage versus the actual average cost of gas in storage.

2.0 Reference: Executive Summary and Introduction, page 3

Table 1.1-2

2.1 For each Utility/Region shown in the referenced table, please provide (i) the approved capital expenditures for 2011 and (ii) the year-to-date or most recent available actual 2011 capital expenditures.

Response:

The approved capital expenditures for 2011 and the year-to-date actual capital expenditures as of May 31, 2011 are provided in the table below.

	(i)	(ii)	
($'000's) Utility Region	**Approved 2011**	**Actuals May-11**	**Projection 2011**
Mainland	$ 89,669	$ 29,138	$ 88,582
Vancouver Island	$ 25,379	$ 5,248	$ 22,953
Whistler	$ 265	$ 54	$ 446
Fort Nelson	$ 2,813	$ 160	$ 2,799
	$ 118,126	$ 34,600	$ 114,781

The FEU's 2011 year-end forecast for growth capital has been revised downward from 2011 approved amounts to reflect decreases in mains and services activity levels which are indirectly derived from the customer additions forecast. The FEU's 2011 year-end projection of total regular capital is approximately $3.3 million lower than approved, $3.6 million of which is attributable to growth capital.

The FEU's May 2011 actual capital expenditures are representative of historical trending at 30 percent of the annual projected spend, with the majority of capital spend occurring in the 3rd and 4th quarters of the year.

2.2 For each Utility/Region shown in the referenced table, please provide the actual capital expenditures for the whole 2010 year and the 2010 year-to-date capital expenditures for the same period (i.e., the same months) as the response in (ii) of question 2.1 above covers for 2011.

Response:

The actual capital expenditures for the 2010 year and the year-to-date as of May 31, 2010 are provided in the table below.

($'000's) Utility Region	(i) Actuals 2010	(ii) Actuals May-10
Mainland	$ 81,861	$ 26,279
Vancouver Island	$ 17,374	$ 4,972
Whistler	$ 475	$ 184
Fort Nelson	$ 410	$ 83
Total	$ 100,120	$ 31,518

3.0 Reference: Executive Summary and Introduction, pages 3 and 4

OM&A Cost Drivers

3.1 Does FEU consider all of the five bulleted OM&A cost drivers shown on page 4 to be new drivers for this application?

Response:

No, FEI and FEVI categorized changes in their forecast O&M by the same cost drivers in their 2010-2011 RRAs so these are not new cost driver categories. The cost driver categories themselves tend to be fairly stable over a period of time, but the specific items that result in changes to the costs within the categories will change from year to year. For example, although changing codes and regulations can generally be expected to remain a cost driver each year, the specific costs that are required will change as certain codes require one-time expenditures or are of a cyclical nature, and others require a similar funding commitment each year.

4.0 Reference: Executive Summary and Introduction, pages 6-9

Exhibit B-1, Section 3.3.2.2, page 56

FEVI 2012 Reduction in Cost of Gas

4.1 Please explain why a significant reduction in the cost of gas reduces the 2012 deficiency for FEVI (by $33M), while not impacting the 2012 deficiencies of FEI, FEW, or Fort Nelson.

Response:

The revenue deficiencies being reviewed in this Application include the cost of gas for Vancouver Island, but not for Mainland, Whistler or Fort Nelson. This is a result of Vancouver Island having a bundled rate (the rate includes both the delivery and the commodity portions of the rate); both components are set in the revenue requirements process. The other utilities have a separate delivery and commodity portion; the delivery portion is set through the revenue requirements process but the commodity rates are determined in a separate rate setting process.

The cost of gas for Mainland, Whistler and Fort Nelson does not impact the calculation of the revenue deficiency or surplus in this Application because the revenue includes commodity and midstream revenue that fully offsets the forecast cost of gas.

5.0 Reference: Executive Summary and Introduction, page 11

Exhibit B-1, Part 1.2.1

Deferral Account re In-Sourcing of Key Customer Service Functions

Preamble: The pre-filed evidence states:

"Also, in Section 6.3, a deferral account is requested to capture actual expenditures that differ from the forecast 2012 and 2013 O&M expenditure levels for many of the Customer Service functions. The types of uncertainties that the deferral account will address include fluctuations in call volumes, the rate of customer adoption of new communication channels and self-serve options being offered, the stabilization of the new CIS and its impact on the end to end business processes, and any variances in the anticipated duration required for new staff to become skilled and proficient at their responsibilities. The variance account will also capture spending variances in meter reading costs primarily due to the timing of BC Hydro's Smart Metering Initiative and its impact on joint gas/electric meter reads in 2012 and the uncertainty of costs in 2013. These cost variances are largely beyond the control of the Companies and the use of deferrals will avoid the potential for windfall gains or losses to customers or the shareholder during the transition period."

5.1 Please explain how, <u>after the fact</u>, stakeholders and the BCUC will be able to determine the prudence of costs booked to this proposed deferral account. For example, does FEU propose beforehand any metrics related to call volumes, rate of customer adoption, etc., that could be somehow converted into dollars and that would give some guidance as to the prudence of the actual costs incurred?

<u>Response:</u>

A number of measures will be in place for both stakeholders and the BCUC to verify the prudency of costs. These include evaluation against existing Service Quality Indicators along with the assessment against internal metrics that will be closely monitored and will demonstrate the effective balance of service quality against costs incurred.

Service Quality Indicators that have been in place since 2003 (as described on page 35, Section 3.12 of the Application), will continue to remain in place for both the 2012 and 2013 forecast years, and the FEU will continue to attain these service levels with the prudent use of resources.

Furthermore, in the contact centre where call volumes are the primary uncontrollable cost driver, various metrics will be developed to ensure the most effective balance of expenditure and customer service levels will be achieved. Examples of such metrics include cost per interaction, average handle time, and first call resolution. These metrics represent those measures that are commonly tracked in a contact centre environment. While it is difficult to convert these metrics into dollars at this time, they should serve to provide an effective assessment of prudency of costs incurred which can be reviewed and assessed in future revenue requirements applications.

5.2 Would it make sense for the cost variations related to meter reading to be separated from cost variations in other customer service functions in a different account or sub-account?

Response:

The FEU plan to track the meter reading costs separately from the in-sourcing service costs and will have the ability to report on any cost variations in these two components if required. It is for ease of administration that one Customer Service Variance deferral account is being sought.

5.3 Please provide a definition of and provide examples of costs that are not beyond the control of the Companies.

Response:

The amount of control that the FEU exercise varies depending on the type of operating cost under consideration. Examples of costs within the control of the Companies include cost items such as employee expenses, employee travel, office supplies and the use of consultants required for subject matter expertise. However, there are unique circumstances involved in the transitioning to a new in-sourced service delivery framework that affect the customer service costs. These unique circumstances give rise to uncertainties described below, that primarily impact labour costs in the Contact Centres and Revenue Cycle and Billing operations and will be closely monitored and managed in the first few years of operations. It is due to the unique circumstances, wherein the CCE Project is still underway and first-hand knowledge of the new service operations is yet to be acquired, that a deferral account is being sought for the 2012 and 2013 forecast years. Examples of uncertainties that may result in cost variances that are largely beyond the FEU's control are described below:

- Stabilization of the new system and business processes

  The end to end business processes are being developed with the implementation of SAP's customer information system. While the CCE Project is on track according to its planned schedule, the detailed steps of the end-to-end business processes have not yet been fully developed and tested at this time to accurately assess the time required to stabilize the new system processes.

- Level of skilled and qualified applicants

  These include Customer Service Representatives and Billing Operation personnel.

  While comprehensive recruiting and training plans are being developed, the FEU have limited insight into the pool of eligible and qualified applicants it will receive and consequently how fast these new staff members become proficient in performing their new roles.

- Customer adoption of alternative communication channels

  FEU will offer and promote enhanced customer communications self-serve options, including web self serve and Interactive Voice Response (IVR) capabilities. Utilization rates and customer satisfaction will be monitored and while it is anticipated that these alternative channels will have an impact on existing communication channels, the extent to which this will occur is not known at this time.

- Call Volume Fluctuations

  These include customer calls, including those related to an emergency, billing inquiries and account collection. Call volumes are impacted by such items as colder weather and significant variation in gas commodity costs as customers call to seek clarification on their energy usage or statement balance. First-hand experience will enable the FEU to better manage call volume volatility along with the associated impacts from self serve communication channels.

Increased experience and familiarity gained during the first few years of operations will enable the FEU to better understand the impact of these uncertainties both in the way of incremental costs and potential savings, and enable the Companies to forecast operating costs under the new service model with greater confidence in future Revenue Requirement Applications.

6.0 Reference: General

6.1 Please explain how ratepayers are impacted or protected in the event that actual capital expenditures in either 2012 or 2013 or both are less than approved capital expenditures.

Response:

The rates customers pay for the next two years will have already been set, so that if the capital expenditures are greater or less than forecast it will have no impact on ratepayers. Even if capital expenditures were less than forecast it does not necessarily mean that additions to gas plant in service will vary as more of the opening work-in-progress could be completed leaving gas plant in service additions and the Rate Base unchanged. Reduced expenditures could also be a function of fewer customer additions or delays in the progress of project completion in which case capital expenditures would take place later in 2013 or 2014 leaving the total spend for the projects unchanged.

Variances in the gas plant-in-service additions are only one item that could affect the actual investment in Rate Base as well as the achieved Return on Equity. The regulatory compact does not guarantee the utility's return on equity, but sets customers' rates to allow the opportunity for the utility to earn a fair return on equity.

Variances in capital expenditures and gas plant additions will be trued up the next time rates are determined, since the actual results will be embedded in the opening plant balance.

6.2 Please explain how ratepayers are impacted or protected in the event that actual numbers of customers in either 2012 or 2013 or both exceed the approved number of customers in either or both years.

Response:

Please refer to BCOAPO IR 1.19.2.

The rates customers pay for the next two years will have already been set so that if actual customer additions are greater or less than forecast it will have no impact on ratepayers. The risk of the variance in customer additions from forecast is borne by the shareholder. However, the impact of a variance in customer additions is expected to be minimal. Although additional customers result in incremental throughput on the delivery system, and correspondingly, incremental revenues collected by the Companies, additional customers also result in incremental O&M and capital costs incurred by the Companies over and above the costs recovered through rates. Therefore, the incremental revenue collected is eroded by the incremental costs associated with customer additions, likely resulting in a minimal net variance.

For Vancouver Island, the RSDA will capture the impact of the variance in customer additions from forecast.

7.0 Reference: Organizational Performance

Exhibit B-1, Section 3.1.2, page 33

7.1 Going forward, will there be one Balanced Scorecard for FEU as a whole or will each of the included utilities issue such a scorecard?

Response:

Historically, the FEU have had only one common scorecard. Going forward, the FEU intend to continue to have one common scorecard for the Utilities.

7.2 Please provide the Scorecard results for each of the FEU member utilities for the past five years.

Response:

The following are the common scorecard results from 2006 to 2010 for the combined FEU. There are no individual scorecards for each of the utilities.

Over the past five years, changes of note were to the definition of Recordable Vehicle Accidents and Recordable Injuries. In 2009, the definition of the Recordable Vehicle Accident measure was changed in order to align with the Canadian Gas Association reporting which included all avoidable and non-avoidable accidents, irrespective of damage amount. The change was to include accidents valued under $1,000 of damage also. In 2007, the definition of the Recordable Injuries was also changed in order to align with the Canadian Gas Association reporting to include medical treatment injuries in addition to lost time injuries.

Terasen Gas Group 2010 Scorecard

December 2010 Results

terasen Gas

		Results to Data	Target
FINANCIAL	**1. Terasen Gas Group Net Earnings**	**$127.3m**	**$122.5m**
CUSTOMER	**2. O&M per Customer**	**$254.18**	**$255.64**
	3. Base Capital	**$98.9m**	**$111.8m**
	4. Customer Survey Score	**80.0%**	**80.0%**
KEY PROCESSES	**5. Credit & Collections**	**0.18%**	**0.35%**
	6. Integrated Energy Service Offerings	**1.0**	**Progress on new product development initiatives**
			Challenge
EMPLOYEE	**7. Recordable Vehicle Accidents**	**47**	**38**
	8. Recordable Injuries	**32**	**26**
	9. Wellness	**4.0**	**5.3**
	10. Public Safety	***Service Quality Indicator***	

Terasen Gas Group 2009 Scorecard

December 2009 Results

terasen Gas

		Results to Date	Target
FINANCIAL	**1. Terasen Gas Group Net Earnings**	**$112.4m**	**$105.2m**
CUSTOMER	**2. O&M per Customer**	**$234.98**	**$238.09**
	3. Base Capital	**$107.7m**	**$116.5m**
	4. Customer Satisfaction	**80.1%**	***79.0%***
KEY PROCESSES	**5. Credit & Collections**	**0.29%**	**0.35%**
	6. Execution Against Regulatory Priorities		***Revenue Requirement and Cost of Capital***
			Challenge
EMPLOYEE	**7. Recordable Vehicle Accidents**	**38**	**39**
	8. Recordable Injuries	**28**	**31**
	9. Wellness	**5.3**	**5.6**
	10. Public Safety	***Service Quality Indicator***	

Terasen Gas Group 2008 Scorecard

December 2008 Results

terasen Gas

		Results to Date	Target
FINANCIAL	**1. Terasen Gas Group Net Earnings**	**$111.7m**	**$105.2m**
CUSTOMER	**2. O&M per Customer**	**$229.15**	**$231.31**
	3. Base Capital	**$115.4m**	**$124.8m**
	4. Customer Satisfaction	**79.7%**	***79.0%***
KEY PROCESSES	**5. Credit & Collections**	**0.24%**	**0.35%**
	6. Customer Additions	**12,830**	**15,500**
			Challenge
EMPLOYEE	**7. Recordable Veh. Accid.**	**13**	**10**
	8. Recordable Injuries	**20**	**28**
	9. Wellness	**5.1**	**5.6**
	10. Public Safety	***Service Quality Indicator***	

Terasen Gas Group 2007 Scorecard

December 2007 Results

terasen Gas

		Results to Date	Target
FINANCIAL	**1. Terasen Gas Group Net Earnings**	**$108.2m**	**$103.3m**
CUSTOMER	**2. O&M per Customer**	**$224.27**	**$231.00**
	3. Base Capital	**$103.9**	**$102.4m**
	4. Customer Satisfaction	**79.3%**	***78.0%***
KEY PROCESSES	**5. Credit & Collections**	**0.27%**	**0.35%**
	6. Customer Additions	**13,861**	**17,000**
			Challenge
EMPLOYEE	**7. Recordable Veh. Accid.**	**10**	**11**
	8. Recordable Injuries	**31**	**29**
	9. Wellness	**5.7**	**5.3**
	10. Public Safety	***Service Quality Indicator***	

Terasen Gas Group 2006 Scorecard

December 2006 Results

terasen Gas

		Results To Date	Target
FINANCIAL	**1. Terasen Gas Group Net Earnings**	**$105.9m**	**$99.5m**
	2. Kinder Morgan Inc. EPS	**$5.00 US**	**$5.00 US**
CUSTOMER	**3. O&M per Customer**	**$231.41**	**$234.00**
	4. Base Capital	**$103.2m**	**$122.4m**
	5. Customer Satisfaction	**77.9%**	***78.0%***
KEY PROCESSES	**6. Credit & Collections**	**0.32%**	**0.39%**
	7. Customer Additions	**14,417**	**16,900**
			Challenge
EMPLOYEE	**8. Recordable Vehicle Accidents**	**21**	**22**
	9. Lost Time Injuries	**12**	**10**
	10. Wellness	**5.7**	**5.3**
	11. Public Safety	**Service Quality Indicator**	

8.0 Reference: Service Quality Indicators

Exhibit B-1, Section 3.1.2, pages 34 and 35, Table 3.1-2

8.1 Are the SQI results available on a utility basis? If so, please provide them.

Response:

The service metrics in the Application are measured on a combined basis and are not available for each utility separately, except for three Service Quality Indicators for FEVI which are reported in its Annual Report to the Commission. FEI reports on the Service Quality Indicators set out in the FEI 2010-2011 RRA Negotiated Settlement Agreement (Item 6) and are represented in Table 3.1.2 of the Application (Exhibit B-1). Although FEVI did not have Service Quality Indicators included as part of its Revenue Requirements Settlement Agreement it adopted the FEI service metrics in 2006. The SQIs shown in the Application are therefore reported at a combined FEU level. The table below indicates the three SQIs that FEVI reports in its annual report to the Commission.

FEVI Service Quality Indicators

Customer Performance Indicators	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Emergency response time (minutes)	17.4	19.9	15.2	16.6	16.2	19.1	18.9
Directional Indicators							
Leaks per kilometre of distribution lines	0.01 33	0.0045 15	0.0051 17	0.0039 21	0.0028 16	0.0063 37	0.0133 79
Outages caused by Third Party	152	181	245	276	266	183	185

8.2 Please comment on the fact that the Emergency Response Time performance only met or exceeded the benchmark in two years, 2007 and 2008, during the ten-year period 2003-2010 inclusive. Please advise the steps that FEU is currently taking to address this issue.

Response:

The Emergency Response Time SQI for FEI measures average response times to emergencies identified as a hit line with blowing gas and includes incidents both during and after working hours including weekends. The geographical area covered by the metric is for FEI (or the Mainland) which includes the Lower Mainland and Interior service areas.

FEI did not meet the SQI Emergency Response Time target of 21.1 minutes from 2003 to 2006. For the period 2003-2008, FEI marginally missed the target by an average of 15 seconds (1 percent) and shared this information with stakeholders during each Annual Review. We provide the following explanations:

In 2006, FEU changed its processes in dispatching staff to emergencies resulting in one minute improvements in 2007 and 2008.

In 2009, we experienced deterioration in the metric due to a number of non-routine factors and changes in emergency trends. In early 2009, the Lower Mainland and parts of the Interior experienced a once in forty year weather event with significant snowfalls which limited FEI's ability to routinely navigate urban streets and added approximately one minute to the January average compared to a year earlier. In April/May 2009, FEW commenced the Whistler conversion project (conversion of Whistler propane customers to natural gas) which involved the reassignment of skilled resources from the existing FEI field workforce. As a result of temporarily re-deploying some of the existing FEI field workforce to Whistler, the pool of first responders in some of the larger FEI service areas decreased. The project was completed in the Fall of 2009.

Also in 2009, and continuing into 2010 and 2011 were two emerging impacts on the emergency response time metric. The first is less standby or "idle" time availability for first responder technicians. This efficiency was due to the introduction of a new work dispatching system (Distribution Mobile Solution) in October 2008 resulting in technicians having less "standby time" and more core work assignments. We are seeing an increase in the amount of time field employees require to interrupt their core work to respond to emergencies. Depending on the type of job, this unscheduled interruption requires some additional time to make their existing work site safe before proceeding to attend the emergency.

The second factor is related to the significant reduction in hit lines achieved in 2009 through to 2011 year-to- date, how the metric is calculated mathematically, and the changes in the geographic dispersion and weightings of the response times. The mix of emergency incidents (i.e. large centre versus remote area) has recently changed with decreases in the larger cities whereas in remote areas it has remained constant. The response times for rural locations are historically higher than the larger centres due to staffing and geographical distances travelled. The weighting of rural town events has increased and the higher response times recorded in these locations has pushed the overall response time upward.

Both these factors are good for the company and general public (reduction in hit lines) and the ratepayer (reduced idle time for technicians) but cause upward pressure on the emergency response time for these types of events.

In 2010, BC hosted the Olympics which particularly impacted our business practices in the January to April 2010 time period by reducing our available emergency response workforce as some technicians were assigned to Whistler and to venue locations. In addition, road closures and increased traffic at non-traditional times affected our ability to respond in the Lower Mainland. For 2009, 2010 and well into 2011, the availability of Federal Action Plan funding (federal government economic stimulation money) has resulted in infrastructure construction activity continuing into traditionally no-dig months when we typically have minimum emergency response capability. We experienced some of our largest damages/outages in 2010 in the winter months.

With the Whistler conversion project of 2009 and the Winter Olympics of 2010 behind us and the Federal Action Plan funding coming to a close in 2011 we expect 2011 emergency response times to be closer to the 21.1 minute target. However, we continue to examine opportunities to improve emergency response now and in the future. An example is the Automatic Vehicle Location ("AVL") project which is currently in progress. In addition, to other benefits, the AVL system will provide precise vehicle location information allowing dispatchers to identify the closest, qualified, available resource to respond to the emergency.

Also, in relation to the Canadian Gas Association ("CGA") members (other gas distribution companies in Canada), the Companies continues to track and compare emergency response times for all types of emergency events including hit lines, gas odour calls, fire calls, carbon monoxide calls and other emergencies. The CGA / FEU emergency response time metric captures a significantly larger number of events (approximately 28,000) than the SQI "hit lines" metric and the percentage of time the FEU response is under one hour was 97.7 percent in 2010 (97.8 percent in 2009). This result puts the FEU in the top quartile of CGA member companies for overall emergency response time.

8.3 Please comment on the fact that there was a large upwards spike in "Leaks per Kilometer of Distribution System Mains" in 2010 and advise as to how FEU is addressing this issue.

Response:

The increased number of Leaks per Kilometer of Distribution System Mains in 2010 reflects a change in process for reporting and correcting leaks. Commencing in 2006, with the implementation of new processes as part of the Order Fulfillment project, leaks were to be reported by creating an SAP internal document (i.e. Notification). However, it was discovered in 2009 that in many cases Work Orders were being raised to correct the leak without a corresponding Notification. The statistics for reporting Leaks per Kilometer of Distribution System Mains were generated based on Notifications raised; due to the failure to consistently raise a Notification for a leak repair, the numbers of leaks during the 2006 to 2009 period are understated. Also due to the failure to create Notifications for every leak repair, it was not possible to restate the 2006 to 2009 experience. It is noted that the 2010 statistics are consistent with 2002 to 2005 statistics. The FEU monitor leaks as a measurement of system health and continue to maintain and improve programs designed to minimize leaks (e.g. cathodic protection, damage prevention).

9.0 Reference: Compensation Management

Exhibit B-1, Section 3.1.3, page 36-38

9.1 On page 36 it is stated that "… FEU and their employees have adopted cost-shared pension and benefit arrangements." Please indicate when this adoption took place for each of the employee groups.

Response:

Pension contributions are shared 50/50 between employee and employer for our union defined benefit plan and our management and exempt (M&E) defined benefit plan. The 50/50 cost sharing for the union plan has been in place since plan implementation, January 1, 1990. The 50/50 cost sharing for the M&E defined benefit plan has been in place since the inception of the plan on January 1, 2007.

Effective, January 1, 2011, IBEW and COPE union benefits integrated onto the flexible benefits platform. Each collective agreement had a cost sharing aspect included as part of the agreement related to benefits.

9.2 On page 37 it is stated that "[a]s a general policy, FEU establish base and incentive compensation targets so as to compensate executives at a level generally equivalent to the median level of a broad reference group of approximately 200 Canadian commercial industrial companies." Please provide complete details with respect to the composition of the reference group and why the particular companies are appropriate and were selected for the group, the reference group's median levels of base and incentive compensation, a copy of the most recent compensation survey (Hay Group's Paynet Database), and support for the claim that FEU compensation targets are at the median level of the reference group.

Response:

As stated in the preamble, the executive compensation policy of the FEU is to compensate executives at a level generally equivalent to the median level of the Canadian Commercial Industrial Comparator Group. The Canadian Commercial Industrial Comparator Group consists of all publicly traded and privately owned companies in Canada, excluding financial organizations. This comparator group represents a broad spectrum of Canadian industrial organizations with which the FEU compete for executive talent. There are 295 companies in this group. For a complete list of these companies refer to Attachment 9.2a.

The Hay Group Guide Chart-Profile Method of Job Evaluation® is used by thousands of organizations in Canada and worldwide to understand and compare jobs from clerical/trade to management/professional and executive level positions.

In essence, the comparison is made between different aspects of total job content, defined as Know-How, Problem Solving and Accountability. The sum of these measures, expressed in job evaluation "points", represents the value of the whole job as explained in Attachment 9.2b.

All FEU executive positions have been evaluated using the Hay Group method and compared to jobs of a similar content ("Hay Points") in the Hay Group Commercial Industrial database for compensation benchmarking. In contrast to a job title match, this methodology enables the FEU to compare to a more robust sample including many companies that are bigger or smaller but still compete with the FEU for executive talent. The following table sets out the market median levels of compensation.

FEU Position	2011 Market Actual Salary Median*	2011 Market Target Bonus % Median*
President & CEO	$493,100	54%
EVP & VPs**	$205,900 - $273,900	30% - 39%

* Commercial Industrial market data as of 2010 has been projected 2.2% to reflect anticipated 2011 compensation levels.

** Based on the average of the market medians for 7 EVP & VPs.

Please see Attachment 9.2c for a summary of the Base Salary and Target Bonus Analysis.

9.3 With respect to the executive pension plan, would it be less expensive if it were the same as the M&E pension plan?

Response:

The FEU are unable to provide a direct response to this question as the value/cost of executive pension plans varies depending on the demographics of the executives participating in them.

Due to demographic information of the participants, the cost may be more or less expensive compared to the M&E pension plan. As well, the M&E plan is a defined benefit plan, whereas the executive plan for the FEU's executives is defined contribution, so it is difficult to assess over time whether the M&E plan would be less expensive.

9.4 Regarding the "notional contributions" in excess of the RRSP maximum limit, please confirm that they are included in the revenue requirement and explain why they are called notional?

Response:

Yes, the notional contributions are included in the revenue requirement. The contributions are called notional because they are not deposited to an account in the employees' name. The notional account is tracked as a liability of FEI.

9.5 On page 38 it is stated that "[a] key objective of FEU has been to provide a common benefits platform for all M&E employees. …" Would it not be beneficial to have a common benefits platform for all employees?

Response:

Yes, the FEU believe it is beneficial to have a common benefits platform for all employees; however, costs will be a key consideration.

10.0 Reference: Capital Spending

Exhibit B-1, Section 3.1.4.1, page 38

Preamble: On page 38 it is stated that "[c]apital funding requests are prioritized and approved taking into consideration safety and reliability requirements and ensuring that capital is put to its best use while minimizing the impact on customers' rates."

10.1 Please provide a list of FEU capital projects by utility that were proposed for the 2012-2013 test period but not approved. For each such project, please include high level project details, estimated costs, and the reason each was rejected.

Response:

As discussed in Section 6.2 of the Application (Exhibit B-1), Capital Expenditures, the FEU develop capital budgets following different methodologies, depending on the category of capital (i.e. growth, sustaining, etc). These methodologies have been demonstrated to be reasonable in the past. As capital budgets were developed this year for 2012 and 2013, there were discussions to ensure the funding requests were appropriate and valid. Changes may have been made as a result of these discussions. However, no records were kept of these changes which may include projects that were rejected. Of the capital projects for the 2012-2013 test period that were ultimately proposed to the UOC and ELT management teams, none were rejected.

10.2 Please explain how the FEU minimize impacts on customers' rates of such capital spending.

Response:

The FEU minimize the impacts on customers' rates by proceeding with capital spending that addresses the required safety, reliability, operational and customer requirements at a reasonable cost.

11.0 Reference: Capital Spending

Exhibit B-1, Section 3.1.4.1, page 39

Preamble: On page 39 it is stated that "[t]he FEU Capital Approval policy outlines an approval process with responsibilities and approval limits defined to ensure appropriate capital spending decisions are made. Annual capital budgets are reviewed and approved by the ELT and UOC. Subsequently, before capital spending occurs in the year, capital projects are reviewed to ensure appropriateness of budget estimates, priority and availability of staffing and resources to implement."

11.1 Please provide a copy of the capital budgets approved for 2012 and 2013 by the ELT and UOC.

Response:

The capital budgets approved for 2012 and 2013 by the ELT and UOC are the same as the forecasts provided in the 2012-2013 Revenue Requirement Application for the FEU. Please refer to Section 6 of the Application (Exhibit B-1), Tables 6.2-1, 6.2-2, 6.2-3 and 6.2-4, pages 332-335.

11.2 Is there any requirement that the Board of Directors approve the budget? If so and if there is any variation from the documents provided in response to 11.1 above, please provide copies of the 2012 and 2013 capital budgets

Response:

The Board of Directors is required to approve the annual capital budget for each of the entities including specific approvals and resolutions for individual projects exceeding $10 million. Board approval for the 2012 capital budget will be sought later this year in the fourth quarter with no changes to the capital budget expected from that filed and ultimately approved in the 2012-2013 Revenue Requirement Application for the FEU.

11.3 Does the last sentence in the quote listed above indicate that after approval by the ELT and UOC, the budget estimates of the projects or even the determination as to which projects proceed may be revised? Please explain fully.

Response:

The majority of capital projects included in the capital budget normally proceed as planned.

When capital budgets are prepared, the best known information and assumptions regarding projects are incorporated. However, as projects proceed further along in the development cycle and with the passing of time, there may be refinements to the projects due to changes in scope and timing. Cost estimates or timelines of projects may be revised closer to the projects' start dates as the result of project dependencies and the availability of resources that may affect the completion of the projects.

As the FEU manage within the total capital funding approved in the annual capital budget, when there are funding increases required for some projects, other existing capital activities may be re-prioritized where possible to make room within the budget for the funding required, without affecting the safety and reliability of the FEU's system. In the situation where a budgeted project does not proceed as planned, the FEU work to identify and advance replacement projects that address other operational requirements.

11.4 On page 39, it is stated that "For large capital projects subject to CPCN requirements, senior management reviews the projects and obtains Board of Directors approval where necessary prior to filing the CPCN applications with the Commission." Is this Board of Directors a utility or a parent company entity?

Response:

The Board of Directors referred to on page 39 of the Application (Exhibit B-1) is the Board of Directors of the utility Companies, responsible for overseeing the activities of the utilities.

12.0 Reference: Forecast Total Energy Demand by Region

Exhibit B-1, Section 4.2, Table 4.2-1, page 76

12.1 Please add a column to the referenced table indicating 2010 Forecast Demand.

Response:

All Companies - Total Energy Demand (TJs)

(In TJs)	2010 Forecast*	2010 Normalized Actuals	2011 Forecast	2012 Forecast	2013 Forecast
Mainland					
Residential	67,829	70,041	70,003	69,890	69,817
Commercial	47,326	46,643	46,790	47,059	47,332
Industrial	46,810	51,538	51,226	51,547	51,559
Mainland Total	**161,965**	**168,222**	**168,019**	**168,496**	**168,707**
Vancouver Island					
Residential	4,892	4,698	4,630	4,576	4,528
Commercial	7,356	7,051	7,066	7,198	7,333
Industrial	22,309	19,526	22,295	22,295	22,295
Vancouver Island Total	**34,557**	**31,275**	**33,991**	**34,069**	**34,156**
Whistler					
Residential	201	224	230	237	244
Commercial	524	541	500	480	465
Whistler Total	**725**	**765**	**731**	**716**	**709**
Fort Nelson					
Residential	263	271	273	273	274
Commercial	277	288	296	304	312
Industrial	72	55	55	55	55
Fort Nelson Total	**611**	**615**	**624**	**633**	**642**
The Companies Total	**197,858**	**200,877**	**203,365**	**203,914**	**204,214**

***Note:** The 2010 Forecast reflects FEI's original application before use rate adjustments in the NSA.
The 2011 Forecast reflects Section 4 of this RRA

13.0 Reference: Forecast Customer Additions

Exhibit B-1, Section 4.2, Table 4.2-2, page 77

13.1 Please add a column to the referenced table indicating 2010 Forecast customer additions.

Response:

Total Customer Additions by Region

	2010 Forecast	2010 Actual	2011 Forecast	2012 Forecast	2013 Forecast
Mainland	5,600	6,913	6,317	6,656	6,923
Vancouver Island	2,320	2,432	2,422	2,557	2,658
Whistler	36	12	18	19	19
Fort Nelson	13	21	23	22	24
All Companies	**7,969**	**9,378**	**8,780**	**9,254**	**9,624** [1]

[1] Please note that the 2010 Mainland forecast reflects the customer addition forecast as filed in its 2010/11 Revenue Requirement Application (Exhibit B-1, page 277). The customer addition forecasts used in the determination of delivery rates for 2010 and 2011 were adjusted through the negotiated settlement process and resulted in forecast Mainland customer additions of 5,952 in 2012 and 6,166 in 2011.

14.0 Reference: Demand Forecast

BCUC Information Request 24.1

14.1 Please provide the forecasted demand (i.e., ex ante) for each year 2003-2011 for FEI and FEVI separately.

Response:

The data for 2003-2011 reflected in the tables below is the forecast demand as filed in the applicable revenue requirement applications and Annual Reviews for each year and may not reflect the demand forecast embedded in delivery rates for each year. Specifically, the forecasts do not reflect approved changes to Residential use rates that may have occurred subsequent to the initial filing in each year. For example, the 2010 and 2011 Mainland Residential use rate was adjusted through the Negotiated Settlement Agreement process and resulted in a forecast residential customer demand of 69,100 TJs in 2010 and 68,600 TJs in 2011.

For Mainland, the total demand excludes FEVI and Burrard Thermal. For Vancouver Island, the 2003 and 2004 data represents actual demand as forecast data is unavailable.

The data contained under the column "2011 Projection" reflects the data in Table 4.2-1 of this Application (Exhibit B-1) and is the most recent forecast of 2011 demand.

Energy (TJs)	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast	2011 Projection
FEI										
Residential	75,100	76,000	76,800	72,900	73,600	72,000	68,600	67,800	67,200	70,003
Commercial	48,900	49,200	49,500	43,800	44,300	46,100	43,000	47,300	48,000	46,790
Industrial	66,500	66,700	66,600	62,000	60,400	53,600	55,700	46,800	46,700	51,226
Squamish					400					
Grand Total	190,500	191,900	192,900	178,700	178,700	171,700	167,300	161,900	161,900	168,019

Energy (TJs)	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast	2011 Forecast	2011 Projection
FEVI										
Residential	4,058	4,228	4,406	4,605	4,772	4,948	5,116	4,892	11,491	4,630
Commercial	7,114	7,197	7,280	7,526	7,564	7,518	7,519	7,356		7,066
Industrial	**21,169*	**21,536*	24,073	21,349	21,363	20,045	20,083	22,309	19,526	22,295
Grand Total	32,341	32,961	35,759	33,480	33,699	32,511	32,718	34,557	31,017	33,991

15.0 Reference: Impact of EEC on UPC

Exhibit B-1, Section 4.3.1, page 82

15.1 Please provide full details of how the 2010 and 2011 estimated declines of 0.12 GJ and 0.16 GJ in Residential average UPC attributable to EEC programs were calculated.

<u>Response:</u>

Please refer to the response to BCUC IR 1.26.1.

16.0 Reference: Residential Net Additions

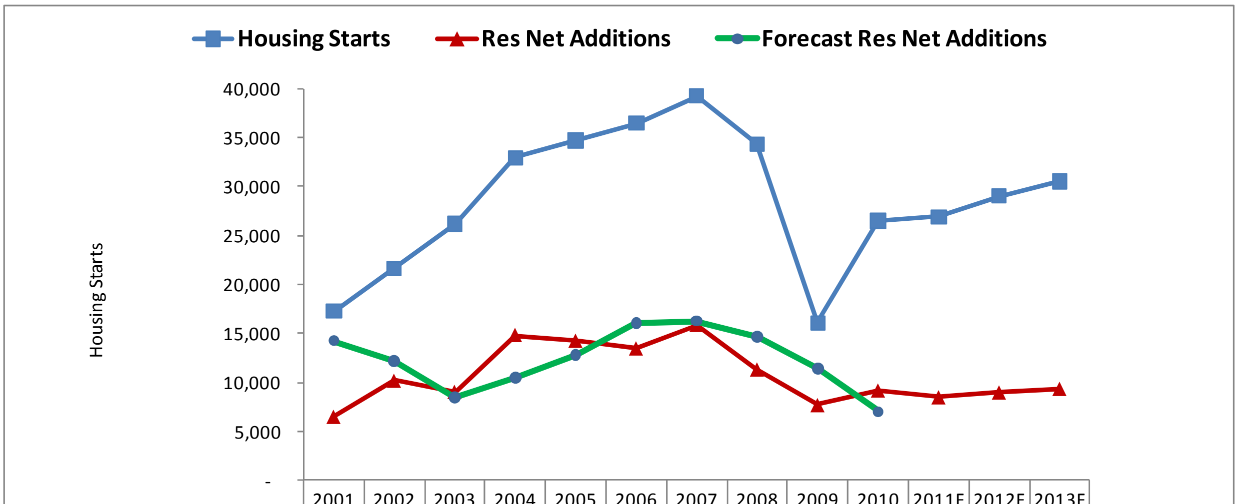
Exhibit B-1, Table 4.3-3, page 84

16.1 Please add a row underneath the table showing forecasted residential net additions for 2001-2010 inclusive.

Response:

The Figure below includes the forecasted residential customer net additions for all companies from 2001 to 2010. The average of actual to forecasted net customer additions is 93 percent from 2007 to 2010.

Please note that the format of this chart has been changed to improve readability.



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011F	2012F	2013F
Housing Starts	17,234	21,625	26,174	32,925	34,667	36,443	39,195	34,321	16,077	26,479	26,900	29,000	30,491
Res Net Additions	6,554	10,180	9,061	14,798	14,214	13,439	15,801	11,318	7,723	9,198	8,517	8,996	9,366
Forecast Res Net Additions	14,257	12,218	8,451	10,500	12,771	16,064	16,255	14,619	11,438	7,022			

16.2 Please provide examples of the types and sizes of adjustments that internal staff make to the CMHC and CBOC housing starts forecast, including any adjustments made for 2012 and 2013.

Response:

Adjustments were made to the net customer additions forecast, which is based on the growth of housing starts forecasted by CMHC and CBOC. The following table shows the types and sizes of the adjustments:

	2011F	2012F	2013F
Housing Starts	26,900	29,000	30,491
Residential Net Additions Before Adjustment	9,110	9,624	10,020
Adjustment by Internal Staff	(593)	(628)	(654)
Residential Net Additions After Adjustment	8,517	8,996	9,366

The downward adjustments reflected the Companies' view on the local housing market and prospective customers.

Adjustments are made based on internal review sessions with residential and commercial sales staff. At these sessions the high level CMHC/CBOC forecast is reviewed. Sales staff and managers then describe the current and planned activity in the smaller regional markets that they are familiar with. Based on these discussions, adjustments are made to the broader CMHC/CBOC forecast. These internal review sessions are consistent with past practices.

17.0 Reference: GDP Correlation to Demand

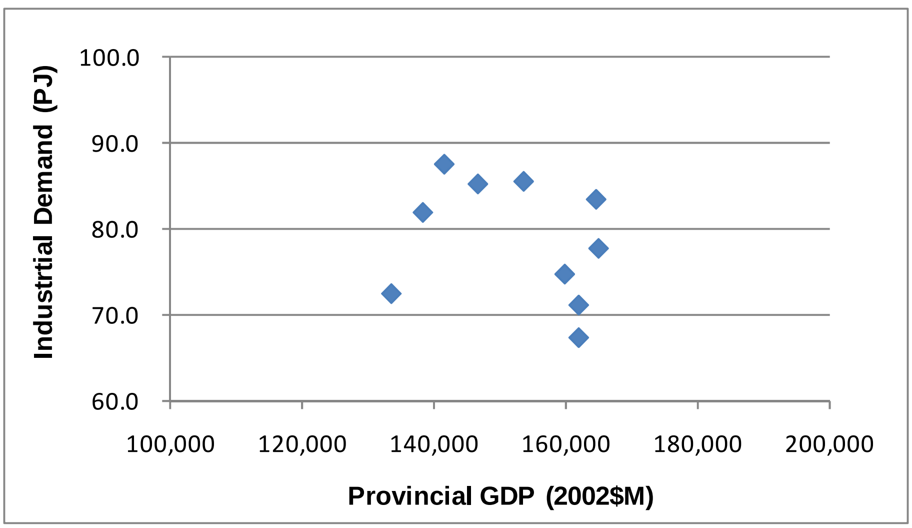
Exhibit B-1, Section 4.3.3, pages 84 and 85

17.1 Please provide separately the historical correlation between (i) GDP and Industrial Demand and (ii) GDP and Commercial Demand.

<u>Response:</u>

(i) GDP does not correlate with the FEU's Industrial Demand. The correlation coefficient calculated based on data from 2001 to 2010 is -0.29. Statistical test shows it is not significant at 95 percent confidence level. The graph below plots GDP and the FEU's Industrial Demand from 2001 to 2010.

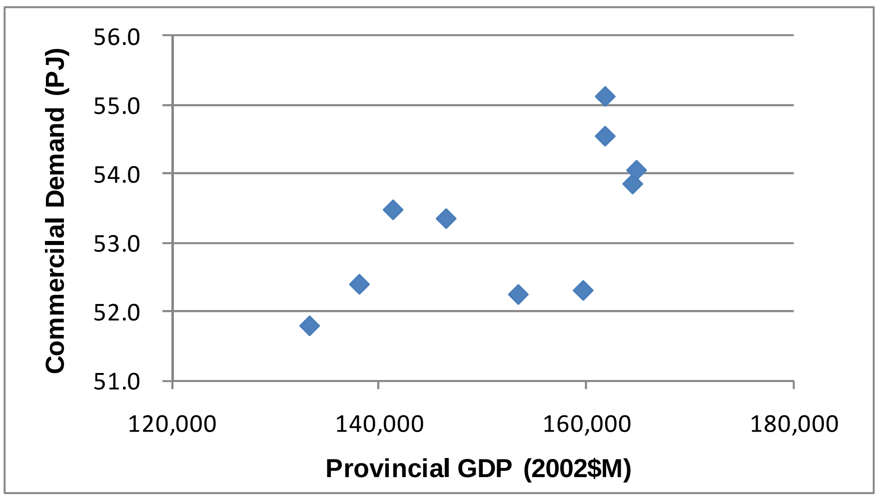
Provincial GDP vs. FEU Industrial Demand



The FEU's customers are grouped into different rate schedule classes based on annual consumption. Each rate schedule class has customers in different sectors. For example, Rate Schedule 25 includes customers in the Wood Products sectors and the Apartment/Condo sector. While the consumption of customer in the Wood Products sector is expected to correlate with GDP, the consumption by the Apartment/Condo sector resembles the pattern of residential rate schedule classes, which is greatly affected by weather. The Companies do not normalize Industrial Demand as a significant portion of it is process loads. In short, there are multiple factors influencing Industrial Demand for natural gas. Depending upon the sectors that the FEU's customers are in, there may not be a relation between their consumption and GDP.

(ii) The analysis shows there is a correlation between provincial GDP and the FEU's Commercial Demand. The correlation coefficient calculated based on data from 2001 to 2010 is 0.65. Statistical test shows it is significant at 95 percent confidence level. The graph below plots GDP and the FEU's Commercial Demand from 2001 to 2010.

Provincial GDP vs. FEU Commercial Demand



Although there seems to be a correlation between GDP and the FEU's total commercial demand, the use of it to predict use per customer is uncertain. The FEU forecast use per customer and accounts for all commercial rate classes. The forecast Commercial Demand is a product of use per customer and accounts. The Companies recognize that there are many factors influencing the demand for natural gas. Quantifying the impact of an individual factor such as GDP on use per customer is a challenge.

The FEU currently do not model GDP in the forecasting process. The Companies believe recent trend analysis provides the best estimate for the short-term forecast.

18.0 Reference: Industrial Demand Forecast Methodology

Exhibit B-1, Section 4.3.6, page 89

18.1 Please provide the participation rates in the Industrial Demand Survey for this year and for the previous two years.

Response:

Industrial Survey		
Year	Customer Participation	Demand/Volume Response Rate
2010	53%	83%
2009	44%	80%
2008	41%	81%

In 2010 the FEU changed the manual FAX-based survey to an electronic email based survey. This was not only easier for FEU to administer but it was also easier for customers to use. As a result the participation rate went up from 44 percent to 53 percent. The survey questions and format was identical to the FAX-based survey.

The demand/volume response rate in the survey only went up 3 percent from 2009. This indicates that more small volume customers participated.

The new electronic email-based survey is also easier for the FEU to process as the results come back in Excel spreadsheets (one per customer) and are loaded directly into the Forecasting database. The FEU intend to further enhance the Industrial Survey and are investigating converting the survey to an online website that could be used to reach more customers more efficiently.

18.2 Do the FEU have any idea as to why the participation rate in this survey is not 100% or close to 100%?

Response:

The FEU are more concerned with the volume covered by the survey than the individual participation rate. It is more important to ensure we get responses from our large volume customers as changes in their usage patterns will have the biggest impact. In 2010, 83 percent of the demand was covered by the survey. The remaining 17 percent of the volume is attributed to the 47 percent of the customers that did not respond.

With in excess of 700 customers we do not expect to achieve 100 percent participation. We do attempt to contact large volume customers that have not responded to the survey via telephone and email to encourage them to complete their form. Due to diminishing returns we limit these efforts once 80 percent of the demand has been covered. Based on past experiences there are clearly some customers that choose not to participate in the survey.

Changes to the survey system this year increased the participation rate from 44 percent in 2009 to 53 percent in 2010 (please refer to the response to BCOAPO IR 1.18.1). Further changes are planned including the conversion to an online web based survey that we hope will increase the participation level even further.

19.0 Reference: Rate Stabilization Adjustment Mechanism

Exhibit B-1, Section 4.4.2, page 92

19.1 Does the FEI agree that the RSAM removes all risk due to variations in UPC, both weather and non-weather related for the residential and commercial classes, from the utility?

<u>Response:</u>

The RSAM for FEI, FEW, and Fort Nelson mitigates the short-term risk that is associated with variances in use per customer for residential and commercial customers.

19.2 Please provide the historical financial impacts on the Companies, for the each year 2003-2010 inclusive, arising from the fact that they have not been protected from variances between recorded and forecast number of customers.

<u>Response:</u>

The FEU are not able to definitively determine the financial impact on the Companies of historic variances in the forecast number of customers because the Companies do not track all of the incremental costs or revenues associated with variances in customer additions. However, a general discussion of the impacts of variations in customer additions, including a high level analysis of the delivery revenue impact for Mainland, has been provided in this response.

A variation in the number of customers results in a variance in throughput on the delivery system, and correspondingly, a variance in revenues collected by the Utilities; however, a variation in the number of customers also results in a variance in O&M and capital costs incurred by the Utilities. For example, if customer additions are greater than forecast, the incremental revenue collected from those additional customers is offset by a corresponding increase in costs, resulting in a minimal net variance or financial impact on the FEU.

To the extent that a financial impact did exist in 2003-2010, additional regulatory mechanisms were in place that captured the full or partial financial impact as follows:

- In the case of FEI, the financial impact of variances in customer additions from forecast would have been included in the 50:50 earnings sharing mechanism with Mainland customers for 2004-2009, mitigating the financial impact for Mainland;

- All variances between revenues and costs (excluding O&M) were captured in the Vancouver Island RDDA or RSDA for 2003-2010; therefore, revenue and cost variances (excluding O&M variances) associated with customer additions would have also been captured in the RSDA/RDDA mitigating the financial impact for Vancouver Island;

- All variances between revenues and costs would have been captured in the Deferred ROE Variance account and the Sales Margin Differential deferral account for Whistler for 2003-2005 and 2007-2009; therefore, variances associated with customer additions would have been captured in those deferral accounts offsetting the financial impact for Whistler.

FEI has provided the revenue variance experienced in 2003-2010 associated with the difference between forecast and actual Residential and Commercial customers, in the table below. This analysis does not reflect the complete financial impact of customer addition variances because it is limited to Residential and Commercial revenue and excludes the offsetting variances in O&M and capital costs; however, it does provide a reasonable proxy of the total delivery revenue impact in FEI because Residential and Commercial customers account for upwards of 85 percent[2] of the delivery margin. The delivery revenue variance is determined by taking the variance in customer additions multiplied by the approved use rate (the variance in use rate was captured in the RSAM for each year) and finally, multiplied by the approved delivery rate.

[2] Section 7, Tab 7.1, Schedules 14 through 15 provide the contribution of margin by rate schedule. The RSAM Rate Schedules have been added together and compared to the total delivery margin in 2012

FEI Delivery Revenue Impact of Customer Variance

Residential and Commercial Customers, ($ Thousands)

Line	Year	Revenue Variance[1]	ESM	FEI Impact (before tax)	Tax Rate	FEI Impact (after tax)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2003	(1,667)	-	(1,667)	37.6%	(1,040)
2	2004	(826)	413	(413)	34.5%	(271)
3	2005	(437)	219	(219)	33.8%	(145)
4	2006	47	(23)	23	33.0%	16
5	2007	(239)	119	(119)	33.0%	(80)
6	2008	402	(201)	201	31.0%	139
7	2009	599	(300)	300	30.0%	210
8	2010	(1,057)	-	(1,057)	28.5%	(756)
9	Total	(3,179)	227	(2,952)		**(1,927)**

[1] Delivery revenue variance is calculated on a monthly basis and is as follows:
(actual customers - forecast customers) * forecast use rate * approved delivery rate

As demonstrated in the table above, the revenue impact of the Residential and Commercial variances was a loss of approximately $3.2 million over an eight year period (column 3), representing approximately 0.08 percent of the total approved delivery margin for that period.[3] When the impacts of the sharing mechanism and tax expense on the revenue are taken into consideration, the financial impact to FEI is less, at approximately $1.9 million (column 7) over the eight year period.

19.3 Please explain why it is appropriate to true up for UPC variances but not for net customer addition variances.

[3] Total approved delivery margin of $3.944 billion for 2003-2010. Please refer to appendix D-5 for the approved delivery margin for 2006-2010.

Response:

The RSAM manages variances in margin from customer usage and is intended as a means of mitigating the effects of unpredictable and uncontrollable factors, namely volume volatility caused primarily by weather and natural gas cost volatility, as well as other factors contributing to a variance in the customer use rates from forecast such as customer behaviour.

The impact on earnings from variations in net customer additions has typically not been significant over time as the revenue impact has been offset by associated impacts on O&M and capital. Please also refer to the response to BCOAPO IR 1.19.2.

19.4 Do the rate structures applicable to the industrial class obviate the need for an RSAM applicable to that class?

Response:

The presence of a fixed demand charge in the industrial customer classes largely mitigates the need for an RSAM for industrial customers in FEI. This is because the delivery margin that the fixed demand charge generates is a significant portion of the total delivery margin allocated to those industrial customers.

19.5 In terms of utility risk, would the FEU agree that weather-related risk is typically a major component of utility risk, in the absence of a true-up?

Response:

The FEU do not agree that weather is a major component of utility risk, regardless of whether or not a true-up exists. Weather is a short term symmetrical risk that should not be taken into account when considering the long term risk of FEU.

However, in the short term, absent a true up mechanism, weather variation can result in earnings volatility that can generate both gains and losses.

20.0 Reference: Mainland Residential and Commercial Use Rates

Exhibit B-1, Section 4.4.3, pages 93-95

20.1 Please provide a full description of the methodology used for the UPC forecasts.

<u>Response:</u>

The FEU use trending analysis to forecast UPC for residential and commercial rate classes. The same methodology is applied consistently across all regions. The Companies assume recent trends implied in the historic data will continue over the forecast period.

The analysis starts with the normalization of historic UPC data to remove the impact of weather variations. The Companies uses the previous 10 years of weather data for normalization.

The next step involves trending four years of normalized UPC values for each region and rate class. If a clear trend is identified, the trend line is used to predict future UPC for the region and rate class. In the absence of a clear trend, the annual percentage UPC change is calculated for the past three years, and this average is used to forecast the UPC over the forecast period.

The forecast UPC is then validated with long term trend data in an effort to minimize errors and establish reasonableness.

The methodology is consistent with that used in the prior years. It has been reviewed and accepted both internally and by the Commission. In addition, a comparison of forecast and actual results, as provided in the response to BCUC IR 1.25.3, supports the reasonableness of the methodology used for the UPC forecast.

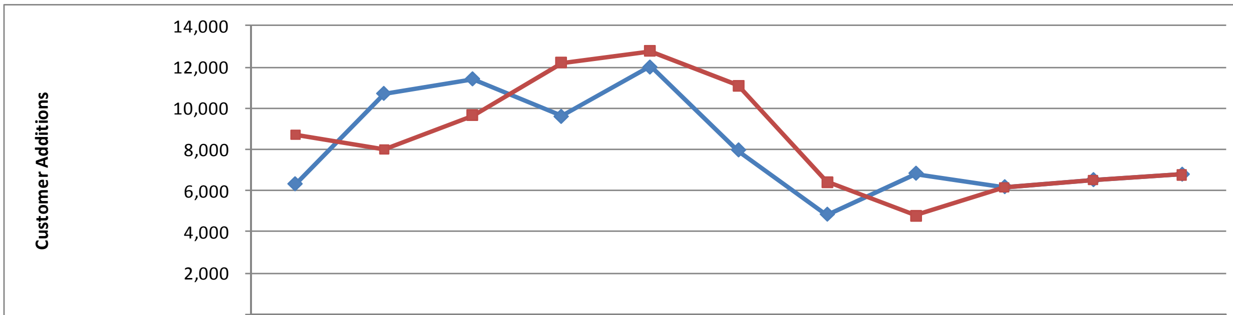
21.0 Reference: Mainland Residential and Commercial Customer Additions

Exhibit B-1, Section 4.4.4, Figures 4.4-7 and 4.4-8

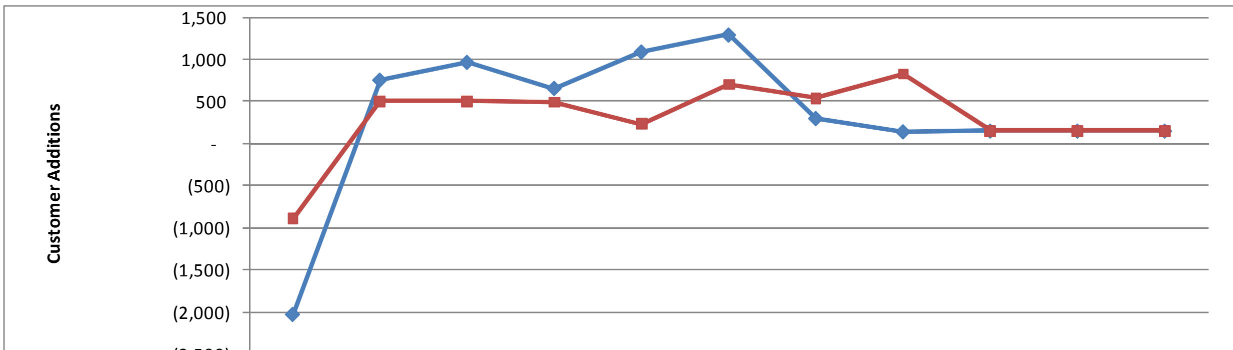
21.1 Please provide a row under each of the two referenced figures indicating the forecasted customer additions for each year 2003-2010 inclusive.

Response:

Please refer to the figures below. As noted in the response to BCOAPO IRs 1.12.1 and 1.14.1, the figures below reflect the customer addition forecast as filed and do not reflect any subsequent adjustments to the demand forecast embedded in approved delivery rates for each year.



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Residential	6,306	10,716	11,427	9,595	12,003	7,959	4,822	6,824	6,165	6,507	6,774
Residential Forecast	8,700	8,000	9,652	12,204	12,764	11,098	6,410	4,777	6,165	6,507	6,774



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Commercial	(2,035)	756	968	658	1,092	1,294	299	141	149	149	149
Commercial Forecast	(890)	500	501	489	235	704	540	823	149	149	149

22.0 Reference: Vancouver Island Demand Forecast

Exhibit B-1, Section 4.5

22.1 Please confirm that the methodology used for FEVI for its demand forecast, i.e., for UPC and customer additions, is the same as that used for Mainland. If unable to so confirm, please provide full details of any methodological differences.

Response:

FEVI confirms that the customer additions forecast methodology for Vancouver Island is the same as used for Mainland.

The normalization methodologies used to prepare the inputs to the UPC forecast process are different for FEVI and FEI. This methodology for each utility is consistent with how UPC's have been calculated for past filings.

Historic use rates must be weather normalized to remove the effects of warmer and colder temperatures. Once use per customer data is weather normalized it can be used to forecast future use per customer values. UPC data for all commercial and residential rate classes in all regions are weather normalized.

Vancouver Island historic use rate data is normalized by first developing a 10 year average heating degree day ("HDD") total. The monthly HDD total from historic data (e.g. 2009) is then compared to the 10 year average for each month and the resulting ratio is the normalization factor for the region in that month. The normalization factor is applied to the UPC data for the selected month and the resulting normalized UPC value is used in the UPC forecasting methodology.

Mainland UPC normalization is prepared using a regression methodology that compares temperature with demand for each residential and commercial rate class. The resulting output is also used to create normalization factors that are then applied to actual use rates. The normalized use rates are then used in the same UPC forecasting methodology as used on Vancouver Island.

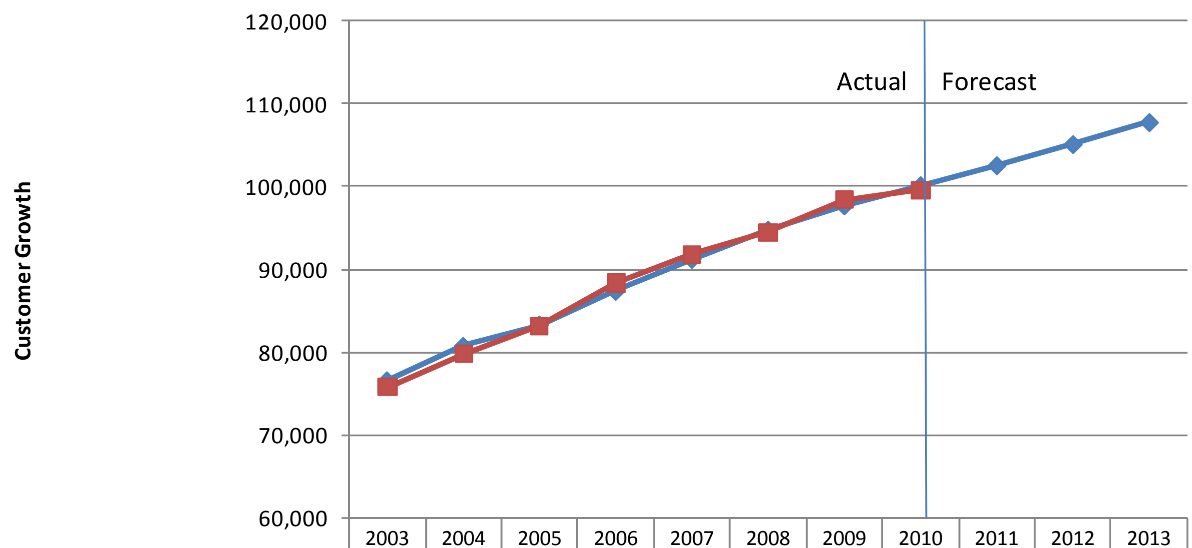
23.0 Reference: Vancouver Island Demand Forecast – Customer Additions

Exhibit B-1, Section 4.5.4, Figures 4.5-5, 4.5-6, and 4.5-7, pages 109-110

23.1 Please provide a row under each of the three referenced figures indicating the forecasted customer additions for each year 2003-2010 inclusive.

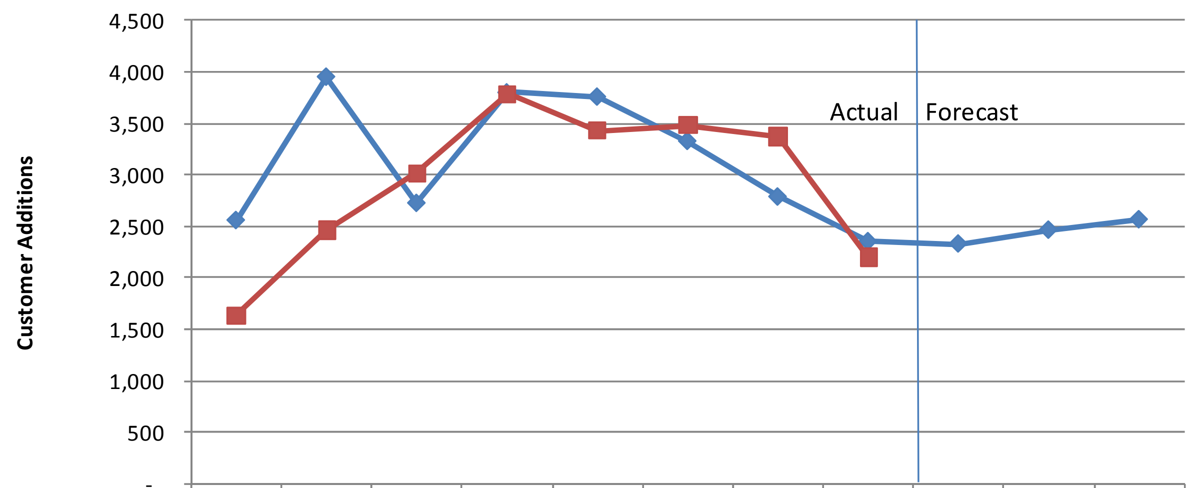
Response:

As shown in the following update to Figure 4.5-5, the forecast gross customer count on Vancouver Island has tracked very closely to observed values. The average forecast to actual ratio since 2007 was approximately 99.9 percent.



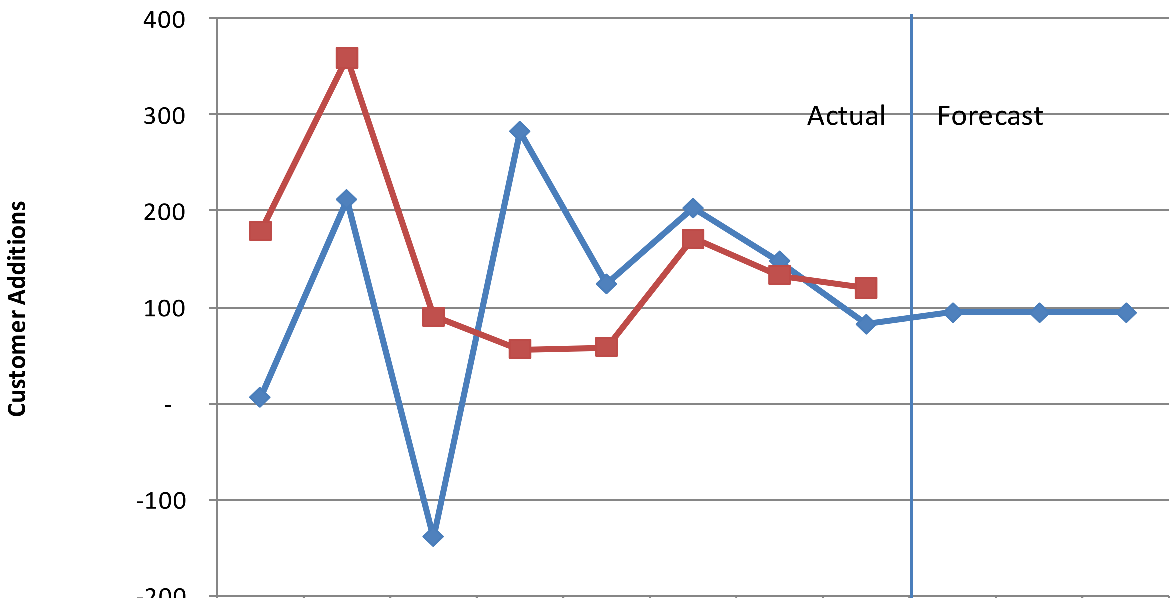
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
All Rate Classes	76,533	80,696	83,280	87,361	91,242	94,771	97,704	100,136	102,558	105,115	107,773
Forecast Yr Ending Customers	75,783	79,733	83,133	88,336	91,822	94,512	98,400	99,600			

The following update to Figure 4.5-6 adds the forecast residential net additions. Since 2007 the average forecast to actual ratio was approximately 98.7 percent. Over the four year period the aggregate actual net residential additions were 256 less than forecast.



	2,003	2,004	2,005	2,006	2,007	2,008	2,009	2,010	2,011	2,012	2,013
Residential	2,556	3,951	2,723	3,798	3,757	3,326	2,785	2,350	2,328	2,463	2,564
Forecast	1,633	2,462	3,013	3,781	3,428	3,479	3,367	2,200			

The following update to Figure 4.5-7 adds the forecast commercial net additions. Owing to the much smaller number of customer additions, the average forecast to actual ratio is much more volatile. Since 2007 the forecasts have averaged approximately 128 percent below actuals. Reversing the trend, the 2010 forecast commercial additions were higher than observed. Considering the four year aggregate since 2007, there were only 75 more net commercial additions than forecast.



	2,003	2,004	2,005	2,006	2,007	2,008	2,009	2,010	2,011	2,012	2,013
Commercial	6	212	-139	283	124	203	148	82	94	94	94
Forecast	179	359	90	56	58	171	133	120			

24.0 Reference: Cost of Service – Cost of Gas by Service Area

Exhibit B-1, Section 5.2.3, pages 138-141

24.1 Do the FEU intend on harmonizing gas commodity costs across all service areas in a future application for postage stamp rates?

<u>Response:</u>

Yes, the FEU intend that any future application for postage stamp rates would also include harmonization of commodity rates.

25.0 Reference: Operations and Maintenance Expense

Exhibit B-1, Section 5.3.1, pages 144-145

25.1 Please identify the internal group or entity which gives final approval to the annual O&M budgets.

Response:

The Executive Leadership Team, comprised of the President and Vice Presidents, as described on page 30, Section 3.1.1 of the Application (Exhibit B-1), grant final management approval to the annual O&M budgets. Further approval of the total annual O&M budget is by the Board of Directors prior to the start of each year.

25.2 Please provide a copy of the O&M budgets by department for 2012 and 2013 as they were internally given final approval.

Response:

The O&M budgets by department for 2012 and 2013 for each of the Companies that have been given final approval are the same as those shown in Tables 5.3-6 through 5.3-13, Section 5.3.3, pp. 156-158 of the Application (Exhibit B-1).

26.0 Reference: Operations and Maintenance Expense – Demographics

Exhibit B-1, Section 5.3.2.5, pages 152-155

26.1 Are there any forecasted savings associated with the "retirement risk" due to the replacement of more experienced employees with less experienced employees? If so, please provide a breakout of these savings and show how the filed evidence recognizes this "savings reward." If not, please explain why not.

Response:

The replacement of experienced workers with less experienced workers does not necessarily have a direct correlation with savings. Assuming these workers are replaced by new hires, there may be savings (less time-off entitlements, enrolment in new benefit plans, generally less need for medical, starting at lower wage steps than outgoing employees at top of their group, etc.). However, depending on the nature of the role, an experienced employee may need to be replaced by another employee with similar experience and knowledge. In the absence of finding a suitable employee internally, an external posting or search may need to be undertaken, particularly in the case of senior, technical, and difficult-to-fill positions.

When experienced employees are replaced internally, it can have a "cascading" effect throughout the organization where ultimately it creates an opportunity for an entry level, or more junior position. An example is the large number of new IBEW hires in Distribution which have contributed to lower overall average charge-out rates, particularly on the capital side (unit cost decreases), which is where most of these new hires are charging their time. However, this is partially offset by having an extra Distribution Apprentice on the crews for training and knowledge transfer. These lower rates are embedded throughout the Distribution budget but the savings are also offset by a general loss in productivity associated with having younger, less experienced workers doing work formerly done by those with many years of cumulative experience.

High levels of employee turnover are generally very costly (i.e. lost productivity, recruiting costs, relocation costs, additional training, and overtime costs for replacement workers) with estimates typically ranging from 30 percent to 150 percent of annual wages depending on the nature of the role and how difficult it might be to fill.

The FEU believe that the total amount of incremental funding requested to address the demographic challenge ($374 thousand in 2012 and $224 thousand in 2013) is very reasonable given the magnitude of the overall retirement risk.

26.2 What assumptions regarding forecasted number of retirements are embedded in this RRA? For example, is the assumption made that every individual eligible to retire will retire as soon as he or she reaches eligibility?

Response:

There are no general assumptions embedded in this RRA regarding the overall number of employee retirements given the uncertain nature of forecasting actual retirements. This uncertainty exists because employees no longer face mandatory retirement. The decision to retire is a very personal one that involves many variables beyond just pension eligibility (e.g. age, health, financial status, family status, job satisfaction, etc.), so it is very difficult to forecast when employees will actually exercise that option. We do know from past experience that 39 percent of employees who were eligible to retire with unreduced pensions between 2005 and 2010 actually did so. However, the actual annual percentage varied dramatically from a high of 61 percent in 2005 to a low of 16 percent in 2009. The data presented in Section 5.3.2.5 of the Application (Exhibit B-1) is simply a representation of the number of employees whose age plus years of service entitle them to either reduced or unreduced pensions between 2011 and 2016. The numbers shown are cumulative year-over-year.

While there have been no general assumptions embedded in the RRA regarding overall forecast retirements, those departments that have requested additional funding to address retirement risk have provided explanations specific to their area. For Distribution, the largest group in terms of headcount and potential retirements, the number of actual retirements is expected to average 20-30 annually for 2012-2013 across all affiliations (IBEW, COPE, M&E). With 90 Distribution employees currently eligible to retire, a group of new hires is expected in the Fall of 2012 to replace outgoing retirees. These impacts are described in detail on Page 173 of the Application.

The Transmission group has identified the need for three transitional field employees in order to manage a number of field workforce retirements in highly skilled and difficult to fill positions that are expected in 2012 and 2013. This is explained on Pages 183 and 184 of the Application.

Human Resources has also requested additional funding to address the need for increased levels of training and related expenses associated with the replacement of retired workers. These requirements are outlined on Page 250 of the Application.

As outlined on Pages 153 and 154 of the RRA, the Companies are continually developing plans and strategies to mitigate the overall retirement risk. These plans must be robust yet flexible given the uncertain nature of forecasting actual retirement.

27.0 Reference: Corporate Services

Exhibit B-1, Table 5.3-74, page 269

27.1 Please add two columns to the referenced table, one for 2010 Actual and the other for 2011 Projected.

Response:

The actual 2010 and projected 2011 costs are included in the table below:

2010 Actual Costs Services (in 000s)	FHI 45.32%	Other 54.68%	Total 100%
Executive	1,437	1,733	3,170
Treasury	185	223	407
Investor Relations	661	798	1,459
Financial Reporting	725	874	1,599
Internal Audit	69	83	151
Board of Directors	987	1,191	2,178
Other	1,071	1,535	2,606
Subtotal	5,133	6,437	11,571
Less: Fortis Properties Management Fee Revenue	(680)	(820)	(1,500)
Less: Pole Rental Revenue	(653)	(788)	(1,441)
Total	3,801	4,829	8,630

Forecast 2011 Estimated Costs Services (in 000s)	FHI 44.61%	Other 55.39%	Total 100%
Executive	1,591	1,976	3,567
Treasury	215	267	482
Investor Relations	674	837	1,510
Financial Reporting	731	908	1,639
Internal Audit	70	87	156
Board of Directors	756	938	1,694
Other	843	1,046	1,888
Subtotal	4,879	6,058	10,938
Less: Fortis Properties Management Fee Revenue	(669)	(831)	(1,500)
Less: Pole Rental Revenue	0	0	0
Total	4,210	5,227	9,438

28.0 Reference: Corporate Services Costs

Exhibit B-1, Table 5.3-75

28.1 Please confirm that the net corporate services costs allocated to FEU are projected to increase by 3.7% in 2011 and forecast to increase by 6.2% and 3.0% in 2012 and 2013 respectively.

Response:

Based on Exhibit B-1, Table 5.3-75, the increases in corporate services costs is approximately 3.7 percent in 2011, 6.3 percent in 2012 and 3.0 percent in 2012. The allocation of the net corporate services to each of the FEU is outlined on Table 5.3-76 Annual Corporate Services to be Allocated from FHI. The annual increases to the net corporate services costs allocated to the FEU (the sum of the FEI, FEVI and FEW rows in Table 5.3-76) for 2011, 2012 and 2013 are approximately 1.0 percent, 10.3 percent and 3.1 percent, respectively. As outlined on page 267 of the Application (Exhibit B-1), the 2012 increase in the corporate services costs is primarily due to inflation, the loss of sundry pole rental revenue at Fortis Inc. and higher headcount in both Taxation and Internal Audit. The FEU benefited in 2010 and 2011 from pole rental revenue which helped alleviate costs at Fortis Inc.

29.0 Reference: Total Shared Services Costs

Exhibit B-1, Table 5.3-77, page 274

29.1 Please extend the referenced table to include all historical years prior to 2010.

<u>Response:</u>

Following is the Total Shared Services Costs table which have been extended to include 2006-2009.

It should be noted that prior to 2010, the Shared Services agreement for the provision of administration and support services to FEW was with FEVI rather than FEI. The amount provided for Shared Services to FEW was an allowed amount that was being inflated annually by CPI.

('000's)	Actual				Approved		Forecast					
	2006	2007	2008	2009	2010	2011	Incremental 2012 vs 2011	% Allocation	2012	Incremental 2013 vs 2012	% Allocation	2013
Total Costs included in Shared Services Pool	46,959	50,573	53,231	56,391	70,313	73,338	14,202	100.00%	87,540	4,710	100.00%	92,250
Allocated to FEVI	4,840	5,104	5,477	5,794	7,239	7,541	1,499	10.6%	9,040	498	10.6%	9,538
Allocated to FEW					202	212	39	0.3%	251	13	0.3%	264
Allocated to FEI	42,119	45,470	47,754	50,597	62,872	65,585	12,664	89.2%	78,249	4,199	89.2%	82,448

The following table shows the Shared Services Costs charged by FEVI to FEW from 2006 - 2009.

('000's)	Actual			
	2006	2007	2008	2009
Allocated to FEW from FEVI	228	234	240	245

30.0 Reference: Rate Base – CIAC

Exhibit B-1, Section 6.2.6, pages 379-381

30.1 Please provide details supporting the Mainland CIAC projection for 2011 and CIAC forecasts for 2012 and 2013.

Response:

FEI's CIAC projection for 2011 and CIAC forecasts for 2012 and 2013 are based on an internal spending model that takes into account historical actuals over the past five-year period coupled with actual current spend to date for all capital activities. As municipalities typically do not develop and release their capital plans in advance of their calendar year, FEI does not maintain detailed documents to support its anticipated CIAC activity on a per project basis.

FEI's CIAC projection for 2011 and CIAC forecasts for 2012 and 2013 are consistent with historical spending if non comparable data is excluded such as the Biomethane Upgrader recovery of $566 thousand in 2011 and the Deferred Service Line Installation Fee transfer of $1.443 million in 2010.

30.2 Please explain the variance between the Mainland approved 2011 CIAC and projected 2011 CIAC.

Response:

The variance between the FEI approved 2011 CIAC and projected 2011 CIAC is mainly driven by an increase in CIAC sustainment capital based on anticipated receivable work for third-party mains and service renewals and alterations and other sustainment related recoverable projects.

Based on communications with the Ministry of Transportation, FEI is aware that municipalities are announcing that they will be increasing spending on underground infrastructure replacement. As FEI deals with well over 100 municipalities, it is highly probable that FEI will have to increase its third-party related work in order to meet increased demand. In addition, FEI's own initiatives to replace buried pipe are anticipated to increase to align with surface rehabilitation.

30.3 Please provide 2010 actual and 2011 projected CIAC for Whistler and for Fort Nelson.

Response:

The 2010 Actual CIAC for Whistler is provided in the table below. Fort Nelson did not have any contributions in aid of construction in 2010.

	2010 Actual	2011 Projection
Growth Capital	(15)	-
Sustainment Capital	2	-
CPCN	-	-
Retirements	(7)	-
Total	**(20)**	**-**

FEW and Fort Nelson do not project or forecast CIAC recoveries because specific receivable projects are not known or forecasted in advance. Actual CIAC recoveries for FEW and Fort Nelson have been very minimal in the last five-year period.

Attachment 9.2

Attachment A – Commercial Industrial Comparator Group (N = 295)

A&W Food Services of Canada Inc.
ACA Co-operative Limited
AV Nackawic Inc.
Abbott Laboratories, Limited
Abbott Products Inc.
Agfa Healthcare Canada
Agfa Inc.
Agnico-Eagle Mines Limited
Ainsworth Engineered Canada L. P.
Air New Zealand
Air Products Canada Ltd.
Aker Chemetics
Akzo Nobel Canada Inc.
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.
Axcan Pharma Inc.
BASF Canada Inc.
BHP Billiton - Ekati Diamond Mines
BIC Graphic Canada
Babcock & Wilcox Canada Ltd.
BakeMark Ingredients Canada Ltd.
Barrick Gold Corporation
Baxter Corporation
The Bay
Bayer Inc.
The Beer Store
Beiersdorf Canada Inc.
Bekaert Canada
Belden CDT (Canada) Inc.
Bericap North America Inc.
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
CHEP Canada
CKF Inc.
CNH America, LLC.
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.
Chubb Edwards
The Churchill Corporation
Co-op Atlantic
Coca-Cola Bottling Company

Twin Rivers Paper Company
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

MDA
MDS Nordion
MMG Resources Inc.
Mainstream Canada Ltd.
McCormick Canada Co.
McElhanney Consulting Services Ltd.
The McElhanney Group Ltd.
McElhanney Land Surveys Ltd.
Meridian Lightweight Technologies Inc.
Methanex Corporation
Michelin North America (Canada) Inc.
Mitsubishi Canada Limited
Montship Inc.
The Mosaic Company
Mother Parkers Tea & Coffee Inc.
Mustang Survival Corp.
Mylan Pharmaceuticals ULC
NOVA Chemicals Corporation
Neopost Canada
Nestlé Canada Inc.
New Horizon System Solutions LP
Newmont Mining Corporation of Canada Limited
Northern Pulp Nova Scotia Corp.
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
L'Oréal Canada Inc.
Osler, Hoskin & Harcourt, LLP
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
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.
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.
SMS Equipment 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
The Shaw Group Limited
Sherritt Coal
Sherritt International Corporation
Shore Gold Inc.
Sidel Canada Inc.
Siemens Canada Limited
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
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

Cognis Canada Corporation
Compass Group Canada
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.
DENSO Manufacturing Canada, Inc.
DSM Nutritional Products Canada Inc.
Daishowa-Marubeni International Ltd.
Danfoss Inc.
Danone Canada Inc.
Davis + Henderson
De Beers Canada Inc., Corporate Division
De Beers Canada Inc., Exploration Division
De Beers Canada Inc., Mining Division
Deeley Harley-Davidson Canada
Dow Chemical Canada Inc.
Dow Corning Canada Inc.
Dr Pepper Snapple Group
Dundee Precious Metals
EFW Radiology
E.I. du Pont Canada Company
EWOS Canada Ltd.
Eaton Corporation
Eli Lilly Canada Inc.
Elkem Métal Canada Inc.
Enbridge Gas Distribution Inc.
Essar Steel Algoma Inc.
Evonik Degussa Canada Inc.
FANUC CNC AMERICA Corporation
FMC of Canada, Ltd.
Ferrero Canada Limited Commercial Division
Ferrero Canada Limited Industrial Division
Finning (Canada)
Finning International Inc.
Fisher & Paykel Healthcare Inc.
FundSERV Inc.
G4S Cash Services (Canada) Ltd.
GDF SUEZ Energy North America, Inc.
Galderma Canada Inc.
Gates Canada Inc.
General Kinetics Engineering Corporation
GlaxoSmithKline Inc.
Goldcorp Inc.
Graceway Pharmaceuticals
Grand & Toy
Griffith Laboratories Limited
Group SEB Canada Inc.
Gulf Chemical Canada
HDS Retail North America
H. H. Angus & Associates Limited
H.J. Heinz Company of Canada Ltd.
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
INVISTA (Canada) Company
Ingersoll-Rand Canada Inc.
Innophos Canada Inc.
Interquisa Canada
J. Ennis Fabrics Ltd.
J. H. Ryder Machinery Limited
JTI-Macdonald Corp.
JYSK CANADA
John Deere Limited Canada
Johnson Matthey Ltd.
Katz Group Canada Ltd.
Kellogg Canada Inc.
Kennametal Ltd.
Kinross Gold Corporation
Kongsberg Automotive
Kruger Products
LANXESS Inc.
Labatt Breweries of Canada
Lake Shore Gold Corp.
Lantic Inc.
Lehigh Hanson
Levi Strauss & Co. (Canada) Inc.
Lilydale Inc.

Attachment B – Job Evaluation

The Hay Group Guide Chart-Profile Method of Job Evaluation[SM] was developed by Edward N. Hay in the early 1940's and has been modified over the years to reflect the changing needs of organizations. It is the most widely used process in the world for evaluating jobs. Two principles are fundamental to the Guide Chart-Profile method:

1. An understanding of the content of the job to be measured
2. The direct comparison of one job with another job to determine relative value

The method is based on Hay Group's long experience (over 50 years) with both private and public sector clients. Job evaluation is the systematic process for ranking jobs logically and fairly by comparing job against job or against a pre-determined scale to determine the relative importance of jobs to an organization

The evaluations are of jobs not people:

- Performance, Individual qualifications and seniority of the incumbent is not considered
- Potential or current pay of the incumbent is irrelevant
- The number of candidates available for a job or the dollar value the market puts on the job do not make the job any larger or smaller
- These factors are ignored during job evaluation. They are taken into account in the pay administration process

The Hay Group job evaluation methodology is based on three main factors:

- Know-How -- The total of all knowledge and skill required to do the job
- Problem Solving -- The amount and kind of thinking required such as analyzing, reasoning, evaluating, creating, and using judgment
- Accountability -- The opportunity the job has to bring about results to the organization

The comparison is made between different aspects of total job content, defined as Know-How, Problem Solving and Accountability. The sum of these measures, expressed in job evaluation “points”, represents the value of the whole job. The three elements are further refined and assessed, as follows:

Know-How: This factor measures the total of every kind of knowledge and skill, however acquired, needed for acceptable job performance. Three dimensions are considered:

- Practical procedures and knowledge, specialized techniques, and learned skills;
- Planning, coordinating, directing or controlling the activities and resources associated with an organizational unit or function; and
- Active, practicing, person-to-person skills in the area of human relationships

Problem Solving: This factor measures the thinking required in the job by considering two dimensions:

- the environment in which the thinking takes place; and
- the challenge presented by the thinking to be done

Accountability: This factor measures the relative degree to which the job, when performed competently, can affect the end results of the organization or a unit within the organization. The opportunity to contribute to an organization is reflected through dimensions, such as:

- the nature and degree of the decision-making or influence of the job;
- the unit or function most clearly affected by the job; and
- the nature of that effect

Attachment C – Commercial Industrial Base Salary and Target Bonus analysis for FEU

Position Title	Base Salary		STI Target %	
	Incumbent	2011 Commercial Industrial Median*	Incumbent	2011 Commercial Industrial Median
President & CEO	500,000	493,100	50%	54%
EVP Finance, Regulatory and Energy Supply	306,000	273,900	40%	39%
VP Energy Solutions & External Relations	267,700	251,000	40%	39%
VP Energy Supply & Resource Development	251,000	239,900	40%	38%
VP Operations (Natural Gas)	235,000	231,600	35%	36%
VP Business Planning	230,000	221,000	30%	33%
VP Finance & CFO, Treasurer	235,000	212,000	30%	31%
VP Customer Service	205,900	205,900	30%	30%

* Commercial Industrial data as of 2010 has been projected 2.2% to reflect anticipated 2011 compensation levels.