FORTIS BC™

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June 30, 2011

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

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

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") 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 CEC 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. Reference: Exhibit B-1, Table 1.1-1, Page 2 & Figure 1.1-2, Page 6; Exhibit B-1, Page 3 & Page 4; Exhibit B-1, Tab 7.1, Schedule 1, Page 426

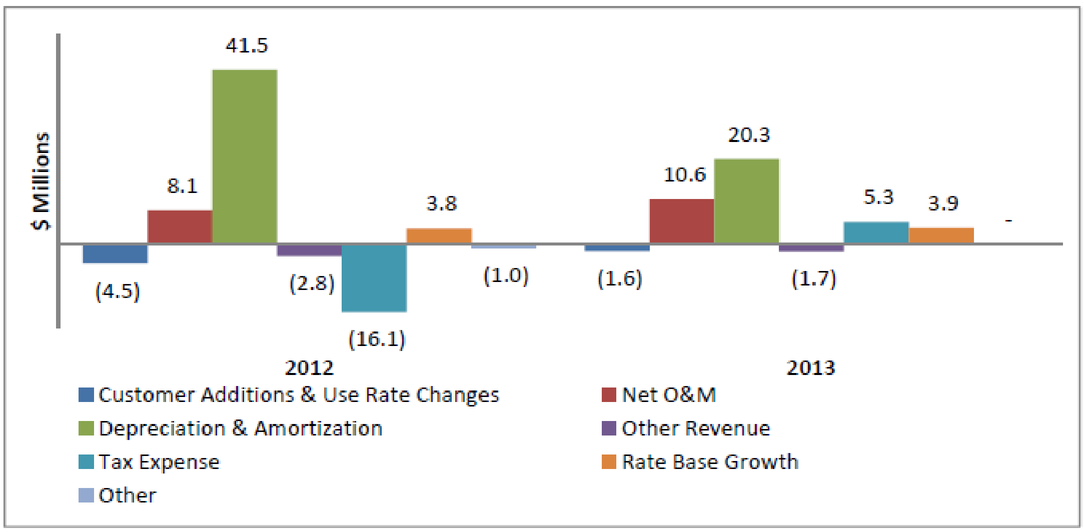
Table 1.1-1: Mainland, Whistler and Fort Nelson Delivery Rate Increases[23]

Utility/Region	2012	2013	Total
Mainland	5.04%	6.36%	11.40%
Whistler	2.23%	11.90%	14.12%
Fort Nelson	6.51%	1.64%	8.15%

Overall, the primary drivers for the revenue deficiencies are in the four categories described below.

Reference: Exhibit B-1, Page 2

Figure 1.1-2: Mainland Revenue Deficiency Components[4]



Reference: Exhibit B-1, Page 6

The increases to rate base in 2012 and 2013 are a result of both regular capital expenditures, including the incremental capital related to the Long Term Sustainment Plan as discussed in section 1.2.4.3 below, and the implementation of large projects, such as the Mount Hayes LNG Facility, the Customer Care Enhancement ("CCE") Project, the Fraser River, Kootenay River, Muskwa River and Tilbury projects, and the recently approved Victoria Regional Operations Centre. Balances in the Energy Efficiency and Conservation and other deferral accounts are also significant contributors to changes in rate base. Offsetting these increases are reductions in Gas In Storage due primarily to lower commodity rates.

Reference: Exhibit B-1, Page 3

- Labour inflation and benefits;
- Codes and regulations spending, reflecting our continued focus on maintaining the safety and reliability of our system summarized in Section 1.2.4.1 and 1.2.4.2;
- Customer and stakeholder expectations, reflecting the in-sourcing of key customer service functions and meter reading cost increases in 2013 (summarized in Section 1.2.1), and also the implementation of our long term resource planning initiative;
- Demographic challenges; and
- Service standards and reliability, driven in part by our Long Term Sustainment Plan requirements summarized in Section 1.2.4.3.

Reference: Exhibit B-1, Page 4

Summary of Rate Change — May 4, 2011 — Section 7, TAB 7.1, Schedule 1

Mainland

	2012 ($ Millions)		2013 ($ Millions)		Total ($ Millions)		Cross Reference
Volume/Revenue Related							
Customer Growth and Use Rates	$ (4.5)		$ (1.6)		$ (6.2)		
Change in Other Revenue	(2.8)	(7.3)	(1.7)	(3.3)	(4.5)	(10.7)	
O&M Changes							
Gross O&M Increases	9.4		12.4		21.8		
Less: Capitalized Overhead	(1.3)	8.1	(1.7)	10.6	(3.1)	18.7	
Depreciation & Removal Cost Provision							
Change in Depreciation Rates	4.6		-		4.6		
Tax Expense Impact of Depreciation Changes	7.5		2.0		9.5		
Depreciation from Net Additions	12.9		5.5		18.4		
Removal Cost Provision	4.9	29.9	0.5	8.0	5.5	37.9	
Amortization Expense							
CIAC	0.4		0.1		0.5		
Deferral Accounts	11.2	11.6	12.3	12.3	23.5	23.9	
Other							
Property and Other Taxes	(0.6)		1.6		1.0		
Other (NSP Provision, Transportation Costs)	(1.0)		-		(1.0)		
Income Tax Rate Change	(2.0)		(0.5)		(2.5)		
Other Income Tax Changes	(13.5)		4.1		(9.4)		
Financing Rate Changes	(4.4)		1.1		(3.3)		
Financing Changes	4.1		0.9		4.9		
Rate Base Growth	4.1	(13.3)	2.0	9.2	6.0	(4.2)	
Revenue Deficiency (Surplus)		$ 29.0		$ 36.8		$ 65.8	- Sect 7-TAB 7.1, Schedule 2 & 3

1.1 Please provide the delivery rate impact for each of the categories of revenue deficiency in addition to the deficiency dollar amounts, for all four utilities.

Response:

The delivery rate impact for each of the categories of revenue deficiency in addition to the deficiency dollar amounts, per utility, is provided below. Please note that a rate change for FEVI is not proposed in this Application, we have provided the notional FEVI rate impact for each category of deficiency for illustrative purposes only.

FEI	2012 Delivery Rate Impact		2013 Delivery Rate Impact		Total Delivery Rate Impact	
	%	$ Millions	%	$ Millions	%	$ Millions
Volume/Revenue Related	-1.28%	(7.3)	-0.57%	(3.3)	-1.85%	(10.7)
O&M Changes	1.41%	8.1	1.84%	10.6	3.25%	18.7
Depreciation & Removal Cost Provision	5.20%	29.9	1.37%	8.0	6.58%	37.9
Amortization Expense	2.02%	11.6	2.13%	12.3	4.15%	23.9
Other	-2.32%	(13.3)	1.60%	9.2	-0.72%	(4.2)

FEVI	2012 Notional Rate Impact		2013 Notional Rate Impact		Total Notional Rate Impact	
	%	$ Millions	%	$ Millions	%	$ Millions
Volume/Revenue Related	11.60%	22.6	-0.89%	(1.6)	10.71%	21.1
Cost of Gas Changes	-21.07%	(41.1)	5.35%	10.2	5.35%	(30.9)
O&M Changes	1.11%	2.2	0.10%	0.2	0.10%	2.4
Depreciation & Removal Cost Provision	4.92%	9.6	0.81%	1.7	0.81%	11.3
Amortization Expense	1.60%	3.1	0.08%	0.2	0.08%	3.3
Other	1.83%	3.6	3.42%	6.8	3.42%	10.3

FEW	2012 Delivery Rate Impact		2013 Delivery Rate Impact		Total Delivery Rate Impact	
	%	$ Thousands	%	$ Thousands	%	$ Thousands
Volume/Revenue Related	6.98%	538.3	1.08%	77.0	8.05%	615.3
O&M Changes	0.42%	32.7	0.10%	7.7	0.53%	40.4
Depreciation & Removal Cost Provision	1.87%	144.2	0.33%	24.0	2.20%	168.2
Amortization Expense	-4.96%	(383.0)	7.56%	581.0	2.59%	198.0
Other	-2.07%	(160.0)	2.82%	217.2	0.75%	57.2

Fort Nelson	2012 Delivery Rate Impact		2013 Delivery Rate Impact		Total Delivery Rate Impact	
	%	$ Thousands	%	$ Thousands	%	$ Thousands
Volume/Revenue Related	-4.05%	(76.0)	-1.36%	(27.0)	-5.42%	(103.0)
O&M Changes	2.47%	46.3	1.37%	26.8	3.84%	73.0
Depreciation & Removal Cost Provision	2.68%	50.3	0.66%	13.3	3.35%	63.6
Amortization Expense	-1.99%	(37.4)	-	-	-1.97%	(37.4)
Other	7.44%	139.4	0.93%	19.7	8.37%	159.1

1.2 Please identify the revenue requirement impact and consequent delivery rate impact for each of the listed large projects, for the regular capital expenditures, for the EEC, for deferral accounts and for gas in storage, for all four utilities.

Response:

The revenue requirement impacts and consequent delivery rate impacts for 2012, and the cumulative impacts for 2013, are shown in the tables below. The revenue requirement impacts represent the approximate depreciation expense, amortization expense, earned return and tax expense (including CCA). Please note that a rate change for FEVI is not proposed in this Application; we have provided the notional FEVI rate impact for illustrative purposes only.

Mainland	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Cumulative Delivery Rate Impact %
Customer Care Enhancement Project	$ 14,505	2.52%	$ 13,929	2.42%
Fraser River Project	$ 644	0.11%	$ 672	0.12%
Kootenay River Project	$ 713	0.12%	$ 699	0.12%
Tilbury Project	$ 1,347	0.23%	$ 1,339	0.23%
Victoria Regional Operations Centre	$ -	0.00%	$ -	0.00%
Mount Hayes LNG Facility	$ -	0.00%	$ -	0.00%
Muskwa River Project	$ -	0.00%	$ -	0.00%
Regular Capital Expenditures [1]	$ 652	0.11%	$ 14,551	2.52%
Energy Efficiency and Conservation deferral	$ (736)	-0.13%	$ 2,027	0.35%
Other deferrals [2]	$ 17,650	3.07%	$ 32,240	5.59%
Gas in Storage	$ (1,901)	-0.33%	$ (1,905)	-0.33%
Total	$ 32,874	5.72%	$ 63,551	11.02%

Vancouver Island	2012 Revenue Requirement Impacts ($thousands)	2012 Notional Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Notional Cumulative Delivery Rate Impact %
Customer Care Enhancement Project	$ 1,576	0.81%	$ 1,531	0.78%
Fraser River Project	$ -	0.00%	$ -	0.00%
Kootenay River Project	$ -	0.00%	$ -	0.00%
Tilbury Project	$ -	0.00%	$ -	0.00%
Victoria Regional Operations Centre	$ 520	0.27%	$ 1,285	0.65%
Mount Hayes LNG Facility	$ 1,405	0.72%	$ 1,261	0.64%
Muskwa River Project	$ -	0.00%	$ -	0.00%
Regular Capital Expenditures [1]	$ 5,830	2.99%	$ 10,142	5.16%
Energy Efficiency and Conservation deferral	$ (554)	-0.28%	$ (249)	-0.13%
Other deferrals [2]	$ (8,967)	-4.60%	$ 2,253	1.15%
Gas in Storage	$ (175)	-0.09%	$ (215)	-0.11%
Total	$ (365)	-0.19%	$ 16,009	8.14%

Whistler	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Cumulative Delivery Rate Impact %
Customer Care Enhancement Project	$ 84	1.09%	$ 85	1.11%
Fraser River Project	$ -	0.00%	$ -	0.00%
Kootenay River Project	$ -	0.00%	$ -	0.00%
Tilbury Project	$ -	0.00%	$ -	0.00%
Victoria Regional Operations Centre	$ -	0.00%	$ -	0.00%
Mount Hayes LNG Facility	$ -	0.00%	$ -	0.00%
Muskwa River Project	$ -	0.00%	$ -	0.00%
Regular Capital Expenditures [1]	$ (6)	-0.08%	$ 53	0.69%
Energy Efficiency and Conservation deferral	$ 6	0.08%	$ 38	0.50%
Other deferrals [2]	$ (833)	-10.80%	$ (136)	-1.78%
Gas in Storage	$ (4)	-0.05%	$ (4)	-0.05%
Total	$ (754)	-9.77%	$ 36	0.47%

Fort Nelson	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement ($thousands)	2013 Cumulative Delivery Rate Impact %
Customer Care Enhancement Project	$ -	0.00%	$ -	0.00%
Fraser River Project	$ -	0.00%	$ -	0.00%
Kootenay River Project	$ -	0.00%	$ -	0.00%
Tilbury Project	$ -	0.00%	$ -	0.00%
Victoria Regional Operations Centre	$ -	0.00%	$ -	0.00%
Mount Hayes LNG Facility	$ -	0.00%	$ -	0.00%
Muskwa River Project	$ 158	8.44%	$ 165	8.68%
Regular Capital Expenditures [1]	$ 57	3.03%	$ 74	3.92%
Energy Efficiency and Conservation deferral	$ -	0.00%	$ -	0.00%
Other deferrals [2]	$ (99)	-5.28%	$ (96)	-5.07%
Gas in Storage	$ -	0.00%	$ -	0.00%
Total	$ 116	6.19%	$ 143	7.52%

[1] Calculation represents change in revenue requirement impacts of "Net Plant in Service, Mid-Year", "Adjustment to 13 month average" and "Work in Progress, No AFUDC" amounts from Section 7, Tab 7.1-7.4, Schedules 39-41 of 2012/2013 RRA, excluding the rate base impacts of the projects shown separately in these tables

[2] Calculation represents change in revenue requirement impacts of "Unamortized Deferred Charges" amounts from Section 7, Tab 7.1-7.4, Schedules 39-41 of 2012/2013 RRA, excluding the rate base impact of the EEC deferral shown separately in these tables

1.3 Please identify the revenue requirement impact and consequent delivery rate impact for each of the O&M cost drivers cited, for all four utilities.

Response:

The 2012 revenue requirement and delivery rate impact, as well as the 2013 cumulative revenue requirement and delivery rate impact, for each of the four utilities are shown in the tables below. Please note that a rate change for FEVI is not proposed in this Application; we have provided the notional FEVI rate impact for illustrative purposes only.

Mainland	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Cumulative Delivery Rate Impact %
Labour Inflation and Benefits	$ 2,033	0.35%	$ 5,807	1.01%
Code and Regulations	$ 1,738	0.30%	$ 2,507	0.43%
Customer & Stakeholder Expectations	$ 839	0.15%	$ 4,322	0.75%
Demographics	$ 374	0.07%	$ 598	0.10%
Service Standards & Reliability	$ 5,100	0.89%	$ 9,203	1.60%
2011 HST Savings	$ (645)	-0.11%	$ (645)	-0.11%
Total	$ 9,439	1.64%	$ 21,792	3.78%

Vancouver Island	2012 Revenue Requirement Impacts ($thousands)	2012 Notional Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	Cumulative Delivery Rate Impact %
Labour Inflation and Benefits	$ (497)	-0.25%	$ (353)	-0.18%
Code and Regulations	$ 58	0.03%	$ 143	0.07%
Customer & Stakeholder Expectations	$ (88)	-0.05%	$ 254	0.13%
Demographics	$ -	0.00%	$ -	0.00%
Service Standards & Reliability	$ 3,147	1.61%	$ 2,822	1.44%
2011 HST Savings	$ (85)	-0.04%	$ (85)	-0.04%
Total	$ 2,535	1.30%	$ 2,781	1.41%

Whistler	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Cumulative Delivery Rate Impact %
Labour Inflation and Benefits	$ 21	0.27%	$ 27	0.35%
Code and Regulations	$ -	0.00%	$ -	0.00%
Customer & Stakeholder Expectations	$ (10)	-0.13%	$ (2)	-0.03%
Demographics	$ -	0.00%	$ -	0.00%
Service Standards & Reliability	$ 29	0.38%	$ 23	0.30%
2011 HST Savings	$ (1)	-0.01%	$ (1)	-0.01%
Total	$ 39	0.51%	$ 47	0.62%

Fort Nelson	2012 Revenue Requirement Impacts ($thousands)	2012 Delivery Rate Impact %	2013 Cumulative Revenue Requirement Impacts ($thousands)	2013 Cumulative Delivery Rate Impact %
Labour Inflation and Benefits	$ -	0.00%	$ -	0.00%
Code and Regulations	$ -	0.00%	$ -	0.00%
Customer & Stakeholder Expectations	$ (136)	-7.26%	$ (136)	-7.15%
Demographics	$ -	0.00%	$ -	0.00%
Service Standards & Reliability	$ 189	10.09%	$ 220	11.57%
2011 HST Savings	$ -	0.00%	$ -	0.00%
Total	$ 53	2.83%	$ 84	4.42%

1.4 Please confirm whether or not Rate Base Growth is the utility's return on equity invested.

Response:

The category "Rate Base Growth" on the Summary of Rate Change (Schedule 1) of Section 7 in the Application represents the change in the utility's equity return as a result of changes in rate base.

The following formula was applied to calculate the Rate Base Growth for all Utilities:

[(Forecast Utility Rate Base – Approved Utility Rate Base) x Equity Thickness x Return on Equity] / 1000.

1.5 Please confirm whether or not the Tax Expense is the aggregate of the income tax changes and the property tax changes.

Response:

FEI interprets this question to be in reference to the Application (Exhibit B-1, page 6, Figure 1.1-2). In Figure 1.1-2, the tax expense category is the aggregate of the income tax changes (excluding the tax expense impact of depreciation changes) and the property tax changes.

1.6 Please provide the explanation for the Other Income Tax Changes, for all four utilities.

Response:

The category of "Other Income Tax Changes" as provided on the Summary of Rate Change (Schedule 1) in Section 7 of the Application, reflects the impact to the revenue requirement of changes in adjustments to taxable income other than depreciation and removal costs. For example, the change in the CCA deduction to determine taxable income is captured in this category. Please refer to Schedules 33 through 35 of Section 7 which provide the comprehensive list of all adjustments to taxable income used in the determination of tax expense.

Please refer to BCUC IR 1.126.1 for additional detail and schedule cross references regarding each of the components in the Summary of Rate Change.

1.7 The CEC would like to understand the explanations for proposed rate increases in consistent terms with consistent definitions and notes that the application explanation basis sometime changes and the definitions sometimes change. Could the FEU prepare a consistent explanation format?

Response:

For Mainland, Whistler and Fort Nelson the proposed rate change is calculated as the revenue deficiency divided by the margin revenue at existing rates. If a rate change were proposed for Vancouver Island, it would be calculated as the revenue deficiency divided by the total revenue at existing rates.

In each revenue requirement, the FEU explain the components driving the rate change in a manner that is relevant and specific to that Application. Generally speaking, the categories and calculations in the summary of rate change remain consistent between revenue requirement applications.

Please refer to BCUC IR 1.126.1 for a detailed review of the Summary of Rate Change (Schedule 1 of Section 7 of the Application), including a description of the calculation and cross references to the financial schedules in Section 7.

1.8 The CEC would also like to be able to break out those revenue requirement changes, which have already been through significant regulatory and approval processes and those revenue requirement changes, which have not been through significant regulatory review. Could the FEU prepare a break out of explanations between those which have been reviewed and those which have not been reviewed?

Response:

FEU interprets "significant regulatory and approval processes" to be CPCN Applications and existing Commission approved deferral accounts and the applications related to Biomethane and CNG and LNG Service. In that context, it is generally the changes in regular capital expenditures, O&M and accounting related changes that have yet to be through significant regulatory and approval processes.

The following tables provide an approximation of the revenue deficiency categorized into three areas:

1. Approval in 2012/13 RRA

This category includes the impact of changes in regular capital expenditures, O&M and depreciation rates and the removal cost provision. Since the FEU are seeking approval for 2012 and 2013 forecasts associated with Biomethane and CNG and LNG Service in this Application, the associated O&M and capital have been included in this total.

2. Significant Regulatory Process or Approval Received

This category includes the impacts of CPCNs and major projects as identified in the response to CEC IR 1.1.2. In the table provided in the response to CEC IR 1.1.2, all projects listed above the line "Regular Capital Expenditures" have been through significant regulatory and approval processes. Furthermore, the FEU have included the total impact of deferral accounts for simplicity.

3. Other

The FEU have also included a category "Other" to reflect volume, other revenue, tax and financing rate impacts.

Please note that this analysis has been completed on a high level basis only, referring to information as calculated in the response to CEC IR 1.1.2 as well as Section 7, Schedule 1. Tables for each utility follow below:

Summary of Rate Change, $ Millions

Alternate View

	Mainland			
	2012	**2013**	**Total**	**Reference**
Approval in 2012/13 RRA				
Net O&M Changes	8.1	10.6	18.7	Schedule 1
Regular Capital Expenditures	0.7	13.9	14.6	CEC IR 1.1.2
Depreciation Rate & Removal Cost Provision Changes	12.7	0.8	13.5	Schedule 1
	21.4	25.3	46.7	
Significant Regulatory Process or Approval Received				
CPCN and Major Projects	17.2	(0.6)	16.6	CEC IR 1.1.2
EEC Deferral Account	(0.7)	2.8	2.0	CEC IR 1.1.2
Other Deferral Accounts	17.7	14.6	32.2	CEC IR 1.1.2
	34.1	16.8	50.9	
Other				
Volume and Revenue	(7.3)	(3.4)	(10.7)	Schedule 1
Property Taxes and Other	0.1	3.5	3.6	Schedule 1
Financing Rate Changes	(4.4)	1.1	(3.3)	Schedule 1
Income Tax Changes	(14.9)	(6.5)	(21.4)	*
	(26.5)	(5.3)	(31.8)	
Total Revenue Deficiency	29.0	36.8	65.8	

*Income tax impacts embedded in "Approval in 2012/13 RRA" and "Significant Regulatory Process or Approval Received"; therefore, notional remaining income tax expense changes not captured in other line items

Summary of Rate Change, $ Millions
Alternate View

	Vancouver Island			
	2012	**2013**	**Total**	**Reference**
Approval in 2012/13 RRA				
Net O&M Changes	2.2	0.2	2.4	Schedule 1
Regular Capital Expenditures	5.8	4.3	10.1	CEC IR 1.1.2
Depreciation Rate & Removal Cost Provision Changes	4.4	0.1	4.5	Schedule 1
	12.4	4.6	17.1	
Significant Regulatory Process or Approval Received				
CPCN and Major Projects	3.5	0.6	4.1	CEC IR 1.1.2
EEC Deferral Account	(0.6)	0.3	(0.2)	CEC IR 1.1.2
Other Deferral Accounts	(9.0)	11.2	2.3	CEC IR 1.1.2
	(6.0)	12.1	6.1	
Other				
Volume, Revenue and Cost of Gas	(18.5)	8.7	(9.8)	Schedule 1
Property Taxes and Other	4.5	0.5	5.0	Schedule 1
Financing Rate Changes	(1.9)	1.7	(0.2)	Schedule 1
Income Tax Changes	9.5	(10.3)	(0.8)	*
	(6.5)	0.6	(5.8)	
Total Revenue Deficiency	(0.0)	17.4	17.4	

*Income tax impacts embedded in "Approval in 2012/13 RRA" and "Significant Regulatory Process or Approval Received"; therefore, notional remaining income tax expense changes not captured in other line items

Summary of Rate Change, $ Thousands

Alternate View

	Whistler			
	2012	**2013**	**Total**	**Reference**
Approval in 2012/13 RRA				
Net O&M Changes	32.7	7.7	40.4	Schedule 1
Regular Capital Expenditures	(6.0)	59.0	53.0	CEC IR 1.1.2
Depreciation Rate & Removal Cost Provision Changes	140.5	2.7	143.2	Schedule 1
	167.2	69.4	236.6	
Significant Regulatory Process or Approval Received				
CPCN and Major Projects	84.0	1.0	85.0	CEC IR 1.1.2
EEC Deferral Account	6.0	32.0	38.0	CEC IR 1.1.2
Other Deferral Accounts	(833.0)	969.0	136.0	CEC IR 1.1.2
	(743.0)	1,002.0	259.0	
Other				
Volume and Revenue	538.3	77.0	615.3	Schedule 1
Property Taxes and Other	79.0	9.2	88.2	Schedule 1
Financing Rate Changes	(73.8)	48.8	(25.0)	Schedule 1
Income Tax Changes	204.5	(299.5)	(95.0)	*
	748.0	(164.5)	583.5	
Total Revenue Deficiency	172.2	906.9	1,079.1	

*Income tax impacts embedded in "Approval in 2012/13 RRA" and "Significant Regulatory Process or Approval Received"; therefore, notional remaining income tax expense changes not captured in other line items

Summary of Rate Change, $ Thousands
Alternate View

	Fort Nelson			
	2012	**2013**	**Total**	**Reference**
Approval in 2012/13 RRA				
Net O&M Changes	46.3	26.7	73.0	Schedule 1
Regular Capital Expenditures	57.0	17.0	74.0	CEC IR 1.1.2
Depreciation Rate & Removal Cost Provision Changes	(40.0)	-	(40.0)	Schedule 1
	63.3	43.7	107.0	
Significant Regulatory Process or Approval Received				
CPCN and Major Projects	158.0	7.0	165.0	CEC IR 1.1.2
EEC Deferral Account	-	-	-	CEC IR 1.1.2
Other Deferral Accounts	(99.0)	3.0	(96.0)	CEC IR 1.1.2
	59.0	10.0	69.0	
Other				
Volume and Revenue	(76.0)	(27.0)	(103.0)	Schedule 1
Property Taxes and Other	43.2	10.4	53.6	Schedule 1
Financing Rate Changes	(14.3)	3.5	(10.8)	Schedule 1
Income Tax Changes	47.4	(7.8)	39.6	*
	0.3	(20.9)	(20.6)	
Total Revenue Deficiency	122.6	32.8	155.4	

*Income tax impacts embedded in "Approval in 2012/13 RRA" and "Significant Regulatory Process or Approval Received"; therefore, notional remaining income tax expense changes not captured in other line items

2. Reference: Exhibit B-1, Page 10

The currently approved rates for the Mainland, and for FEVI, were determined through a Negotiated Settlement Process ("NSP") for 2010 and 2011. The 2010 and 2011 rates for FEW and the 2011 rates for the Fort Nelson division of FEI were determined through oral and written hearing processes, respectively. These recent rate setting processes and other more recent regulatory proceedings laid the foundation for the Utilities to deliver on several initiatives. These included:

1. The in-sourcing of key customer service functions;
2. Enhanced Energy Efficiency and Conservation programs;
3. Expanded service offerings for customers, including:
    1. A two year trial period for a biomethane service offering;
    2. A business model and rate design for Compressed Natural Gas ("CNG") and Liquefied Natural Gas ("LNG") fueling service filed December 1, 2010; and
    3. Approval to pursue Alternative Energy Services (which the Companies are now referring to by the more descriptive name "Thermal Energy Services") within the utility.
4. Increased focus on investments to maintain the safety and reliability of our system; and
5. The development of an interim rate mitigation strategy for our customers on Vancouver Island.

2.1 Does FEU intend that justification for undertaking all of the above initiatives has been dealt with in previous regulatory proceedings and would not be a focus for this revenue requirements proceeding?

Response:

This is in response to CEC IRs 1.2.1 and 1.2.2.

In responding to these information requests, the Companies interpret "justification" to mean that the Companies have demonstrated, or will demonstrate, that the projects or initiatives listed in the preamble are in the public interest, and have received Commission approval or are awaiting Commission approval in a separate regulatory process in order to further develop, implement, or deliver the projects/initiatives.

The Companies believe that they have demonstrated, or will demonstrate, "justification" for developing, implementing, or delivering the listed initiatives, with the following clarification:

- With regard to the enhanced Energy Efficiency and Conservation programs, the Companies are seeking Commission acceptance of a funding envelope of $74.5 million for each of 2012 and 2013 in this regulatory process under section 44.2 of the UCA. This requested funding includes not only previously-approved program areas but also expansion of EEC programs to the Whistler and Fort Nelson service area, offering industrial programs to FEVI customers, and new initiatives such as the Furnace Scrap-It Program.

- With regard to the Thermal Energy Services, the Commission has approved under section 59-61 of the *UCA* a Rate Schedule for Thermal Energy Services and the terms and certain conditions necessary for the Companies to pursue Thermal Energy Services. The Companies will bring individual projects for the Commission's approval under either section 59-61 or section 45 of the *UCA,* depending on the size of the project, outside of this regulatory proceeding.

- "Increased focus on investments to maintain the safety and reliability of our system" is not necessarily confined to a particular project or initiative. Rather, it reflects the requirement to undertake certain activities or initiatives in order to deliver energy safely and reliably. As explained in Section 1.2.4 of the Application (Exhibit B-1), FEI received approval for additional O&M in the amount of $5.3 million in 2010 and a further $2.1 million in 2011 to carry out various activities to meet the requirement. Further funding requests are included in the 2012-2013 RRA related to this initiative.

- "Rate mitigation strategy for Vancouver Island" encompasses a two-stage process: (1) an interim measure - a rate freeze for core market customers at a level that exceeded the cost of service and the creation of a Rate Stabilization Deferral Account and (2) a long term measure - amalgamation of the Companies and the implementation of a harmonized rate structure. The Companies have received approval for the interim measure in the 2010-2011 RRA for Vancouver Island.

In Section 1.2 of the Application (Exhibit B-1), the Companies further summarize the impact and treatment of the listed initiatives or activities relating to the revenue requirements in the test years.

With regard to the costs incurred to date in these projects or initiatives, the costs can be reviewed under the long-established prudency-review principles.

2.2 Does FEU intend that all of the above initiatives can be the subject of prudence of execution review in this regulatory proceeding?

Response:

Please see the response to CEC IR 1.2.1.

3. Reference: Exhibit B-1, Page 11

In Commission Order No. C- 1-10, FEI received approval to in-source key components of customer care services and implement a new Customer Information System ("CIS") through the Customer Care Enhancement Project ("CCE Project"). The CCE Project is progressing on time with an implementation date of January 1, 2012, and the overall project spend remains on track with no variance to the approved spend of $115.5 million.

3.1 Please provide the project status report comparing actual to date to the planned expenditures.

Response:

As of May 30, 2011, the CCE Project expenditure status was:

(000's)

Budget to date	Actual to date	Variance to date
$ 52,128	$ 46,287	$ 5,841

The positive variance is due in part to timing issues against the plan, but overall the Project spend remains on track. As a point of clarification on the approved spend, in Commission Order No. C-1-10, the approved budget was +/- 10 percent of $115.5 Million. FEI has not identified any potential cost items that are currently anticipated to cause the costs to be greater than +/- 10 percent of the $115.5 million and at this time is tracking to the $115.5 million.

3.2 What are the implications for customer rates if the project over-spends or under-spends?

Response:

In accordance with BCUC Order No. G-23-10 and BCUC Order No. C-1-10, if the CCE Project under or overspends within ten percent of the project cost estimate of $115.5 million (including AFUDC), the total costs of the Project will be reflected in rates. If the final cost of the Project varies by more than ten percent of $115.5 million (including AFUDC), the additional costs or savings outside that +/- ten percent band will be shared equally between the FEU and their customers.

The cost of service and corresponding rate proposals for 2012 and 2013 include forecast final CCE Project costs of $115.5 million (including AFUDC). Although unlikely to be material, should any variances in the final costs occur as compared to the costs embedded in this Application, adjustments will be reflected in the next revenue requirement application, with rates likely effective January 1, 2014. In accordance with the terms of BCUC Order No. G-23-10, customer rates would reflect the following:

- If actual final costs are within the +/- ten percent of the forecast of $115.5 million (i.e. final costs in the range of $104.0 million to $127.1 million), one hundred percent of the costs will be reflected in rates;
- If actual final costs are below $104.0 million, $104.0 million plus fifty percent of the variance between the final costs and $104.0 million will be reflected in rates (for example if final costs are $102.0 million, $103.0 million will be reflected in rates);
- If actual final costs are greater than $127.1 million, $127.1 million plus fifty percent of the variance between the final costs and $127.1 million will be reflected in rates (for example if final costs are $129.1 million, $128.1 million will be reflected in rates).

3.3 Please provide an identification of risks for over or under spending and for over or under delivery of planned functionality.

Response:

There are no identified risks to date for any over or under delivery of planned functionality.

As a point of clarification on the approved spend, in Commission Order No. C-1-10, the approved budget was +/- 10 percent of $115.5 Million.

There are currently no identified risks for any material under spending.

There currently are two identified risks for over spend which would be:

1. If the project is unable to go-live as planned; or
2. if the estimated stabilization period of three months after go-live is required to be extended requiring additional third party costs.

At this time, the Project considers the risk of not being in a position to go-live as planned as remote. In the event of such a remote occurrence, it is not possible to reasonably estimate the financial implication as it would be wholly dependent on the reason for and the duration of the delay.

In the unlikely event that the stabilization period extends beyond the planned three months where third-party costs would need to be incurred, the financial impact will be determined by the reason for and the duration of the stabilization period.

> As a result of the implementation of the CCE Project, the Customer Service department has been created to manage the contact centres (located in Burnaby and Prince George), the revenue cycle and billing operations, customer relations, bad debt expenditures, and meter reading services. Overall, the 2012 forecast costs for the Customer Service department show a decline of approximately $1.9 million from the 2011 approved amount, as savings are recognized with the transition to the in-sourced service delivery model. In Section 5.3.7 of this Application, the ongoing services and operating expenses for the Customer Service Department are described in detail, as well as the Utilities' plan to maintain existing service quality measures for the two years of this RRA.

3.4 Please reconcile anticipated project benefits to benefits being realized in the 2012 & 2013 period, including the decrease in customer service costs.

Response:

While a detailed line-by-line project benefits reconciliation cannot be completed due to the nature of the bundled service solution provided by our current outsourced provider, the CCE Project provides for a number of benefits. The Project will help to provide better control over critical customer touch points and processes. The FEU will own and control a new industry standard customer information system (CIS) which will better position the FEU to compete in an increasingly competitive energy marketplace and respond swiftly and cost effectively to customer's changing expectations along with regulatory and legislative change. More detailed project benefits are provided below:

- Customers will benefit from this initiative through the implementation of new billing and payment options, improved billing of non-gas charges and new service offerings, greater access to information through a variety of communications channels and enhanced self serve options including web self serve and Interactive Voice Response (IVR) capabilities.

- The Project will benefit the Province of B.C. through job creation and the associated economic benefits as a result of approximately 300 additional jobs required to carry out the ongoing in-sourced operations.

- This Project will enable the efficient implementation of new products and programs for customers, including energy efficiency programs, through CIS system functionality that is designed to easily add products and services.

- The project will provide the FEU with direct ownership of staff training and management, providing the ability to ensure representatives are positioned to understand all aspects of the business, best meet customer information needs, relate to regionally specific situations and experiences, and to quickly identify and address any issues.

- The FEU will build its own culture within the service delivery organization and expects benefits from lower staff turnover than experienced in outsourced environments, and with representatives who will take pride and ownership of the service they provide customers as a result of being FEU employees.

- While the FEU are a regulated monopoly, we are not without competition, and the new CIS will enable the FEU to effectively add new products and services for customers. Through internal contact centres and ownership of training and management, the FEU will be best positioned to ensure our representatives have the knowledge required to best serve our customers.

- This Project will provide the FEU with the ability to ensure service quality through ownership of the customer experience, service delivery metrics and a CIS platform which will adapt as the business environment changes.

Furthermore, the FEU are well positioned to deliver these benefits to customers through the in-sourced customer service operations framework, at a lower operating cost than the current outsourced arrangement, where any further savings realised in the 2012 and 2013 forecast years will accrue to customers.

3.5 Please explain the FEU activities and focus on achieving further benefits from the new CCE platform now that it is closer to reality.

Response:

While the CCE Project is closer to reality with less than seven months to go-live, it will not be until the FEU have had an opportunity to manage the in-sourced customer service operations first-hand that the FEU will be able to determine whether further benefits than those described in response to CEC IR 1.3.4, can be derived. As such, during the first few years of operations, as the FEU become increasingly familiar with the customer service processes and operating environment, we will continue to seek out opportunities where further benefits can be realized.

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.

3.6 Now that BC Hydro has made its Smart Metering decisions and is proceeding to implementation, has FEU determined what path it will follow with respect to metering?

Response:

Now that BC Hydro is moving ahead with its implementation of Smart Metering, the FEU are beginning to assess future meter reading needs for gas customers based on the need for an independent gas meter reading function. The FEU have negotiated an extension of the current joint meter reading arrangement with BC Hydro to the end of 2012 and have undertaken a market process to identify an alternate service provider to support the manual meter reading function for a further two to five years. In parallel, the FEU are evaluating the impact of having this function performed in-house through this interim period.

The Companies intend to move to a more automated meter reading process in the future and expect to submit an application no earlier than the end of 2011 describing the details of that solution. The alternatives being considered include both drive-by and network supported automated meter reading technologies. The Companies are targeting a technical implementation date of sometime between January 1, 2015 and December 31, 2017.

3.7 Has FEU determined whether or not it will be able to integrate in any useful ways with the BC Hydro initiative to develop joint process benefits for customers as was done with the joint gas/electric meter reading?

Response:

The FEU have not yet determined if there are opportunities to integrate with the BC Hydro initiative to develop joint process benefits for customers. Over the years, the FEU have continued to discuss and assess with BC Hydro where potential synergies of an advanced metering initiative can be realized. Most recently, with BC Hydro's Smart Metering implementation underway there have been more specific discussions related to the possible leveraging of the electric meter reading network infrastructure for use by the FEU to support the Companies' long term gas meter reading requirements.

4. Reference: Exhibit B-1, Page 12

The FortisBC Energy Utilities are providing expanded service offerings for customers in the areas of Biomethane, CNG and LNG Fueling, and Alternative Energy Services (now being referred to in this Application by the more descriptive term "Thermal Energy Services"). The

4.1 Please confirm that the revenue requirements for 2012 and 2013 are not increasing because of the expanded service offerings.

Response:

Confirmed. Overall, the net impact of the Biomethane and CNG and LNG service offerings is a net decrease to the revenue requirement of approximately $1.2 million in 2012 and approximately $1.8 million in 2013. A discussion of each of the two service offerings, as well as Thermal Energy Solutions, is provided below.

I. Biomethane

The impact from Biomethane will increase the revenue requirements for 2012 and 2013 by $1.2 million and $1.5 million respectively, as summarized in the table below. This impact includes the amortization of the Biomethane program costs incurred in 2010 and 2011.

Particulars		2012	2013
Rate Base, Mid-year		$ 3,137	$ 3,859
Return on Rate Base		7.75%	7.75%
Program O&M Expense		$ 467	$ 533
Less: Overheads Capitalized	14%	(65)	(75)
Net O&M Expense		402	458
Depreciation Expense		171	251
Amortization Expense		299	299
Income Tax Expense		152	167
Earned Return		243	299
Total Incremental Revenue Requirement		$ 1,267	$ 1,475

II. CNG and LNG Service Offerings

The impact of CNG and LNG Service Offerings is a decrease to the revenue requirements of approximately $2.5 million in 2012 and approximately $3.3 million in 2013. The following table summarizes the forecast revenues and costs for the CNG and LNG Fueling Service:

Particulars		2012	2013
Rate Base		$ 7,868	$ 12,520
Return on Rate Base		7.75%	7.75%
Station & Transmission O&M Expense		384	605
Less: Overheads Capitalized	14%	(54)	(85)
Net O&M Expense		330	520
Depreciation Expense		475	778
Amortization Expense		(24)	(24)
CNG / LNG Service Revenue		(3,744)	(5,398)
Income Tax Expense		(119)	(152)
Earned Return		610	970
Total Incremental Revenue Requirement		$ (2,472)	$ (3,305)

III. Thermal Energy Solutions

As discussed in the Application (Exhibit B-1), page 275 and in the response to BCUC IR 1.78.1, FEI has allocated $0.5 million in O&M costs to the Thermal Energy Deferral Account for the provision of O&M related services to future Thermal Energy Solutions customers. This allocation ensures that no negative impact on natural gas delivery rates will result from the development and delivery of thermal energy solutions.

4.2 Please confirm that the expanded service offerings are expected to pick-up overhead costs from the FEU natural gas revenue requirements and may contribute to natural gas customer delivery rate reductions through increased through put.

Response:

In aggregate, the FEU expect the three expanded service offerings identified in the reference and preamble to this question will capture overhead (the FEU assume the terms "overhead" and "O&M" are synonymous in this response) costs and create increased revenues that will benefit customers through lower delivery rates. The impact of each individual service offering is described below, followed by a discussion of the aggregate impact.

I. Biomethane Service

The biomethane service will result in an increase in O&M in two ways. First, the majority of O&M costs for biomethane service are related to biogas supply and delivery. These costs will be recovered through revenues from only those customers who choose to receive biogas service. In this case, the increased revenues from biomethane service will offset the increased O&M and have no net effect on delivery rates for all customers. Second, there will be increases in O&M required to make this offering available to all customers (customer education for example) that will be recovered from all customers, resulting in a small upward impact on delivery rates. This impact to delivery rates is expected to remain minimal.

For the period of this Application, the throughput associated with the biomethane service offering does not contribute to delivery rate reductions because it does not represent incremental or additional throughput on FEI's delivery system; rather, it offsets the existing throughput of natural gas. However, over the long term, as biomethane availability improves, many customers who would have chosen to use some other energy form or switch their primary energy source in order to reduce their carbon footprint may instead choose to use or remain on the natural gas system and use biomethane as their preferred energy source. In this way, the biomethane service is an important new service to help maintain system throughput and thus have a long term downward impact on delivery rates.

II. CNG and LNG Fueling Service

CNG and LNG Fueling service will also have increased O&M that will be recovered through revenues from those customers who choose to receive the service. FEI expects the availability of this service to potential transportation customers could generate substantial sales, increasing the overall gas throughput on the system. This increased throughput could result in more volume on the system over which to recover the O&M for all customers, thus having a downward impact on delivery rates. This downward impact is expected to grow as we gain success in adding to our CNG and LNG customer base. At some point in the future, if biomethane is made available to CNG and LNG fueling service customers, additional uptake of fueling services may result as these customers strive to reduce emissions from their fleets to an even greater extent.

The NGV business initiative as a whole represent a significant long-term business opportunity to protect existing customer delivery rates, while exposing existing customers to very little risk given the structure of the current business model that FEI has proposed.

III. Thermal Energy Solutions

As discussed in Section 5.3.18.2 of the Application (Exhibit B-1), FEI has allocated a charge, $0.5 million, from the gas business to Thermal Energy Solutions for recovery of O&M representing the administrative costs of supporting the business in both 2012 and 2013. Furthermore, all direct O&M costs (including project costs) are captured in the Thermal Energy Service Deferral Account, as discussed in Appendix G of this Application. These allocated and direct O&M costs will be recovered from future Thermal Energy Solutions customers. This allocation ensures that no negative impact on natural gas delivery rates will result from the development and delivery of Thermal Energy Solutions. An increase in natural gas throughput as a result of Thermal Energy Solutions has not been forecast in this Application.

Aggregate Impact

The downward impact on delivery rates from the CNG and LNG service more than offsets the upward rate pressure of the O&M costs for Biomethane recovered from all customers. This is clearly demonstrated by the combined impact of the Biomethane and CNG and LNG service offerings in this Application, which is a net decrease to the revenue requirements of approximately $1.2 million in 2012 and approximately $1.8 million in 2013.[1] FEI expects that this net benefit will continue, and may grow, as we gain success in our CNG and LNG customer base as well as with our Biomethane service offering.

All of these service offerings are important new services that the FEU have initiated to meet the evolving needs of our customers. Our efforts to expand the services that customers are seeking from us to help meet their energy and GHG reduction needs are all important in keeping natural gas as a part of the energy mix and have throughput on the system up. In these ways, the expanded services offered by the FEU has an important overall downward impact on natural gas delivery rates.

[1] Please refer to CEC IR 1.4.1

4.3 Reference: Exhibit B-1, Page 72

Table 3.4-1: The RSDA Mitigates Rate Impacts Today and in the Future,

($ Thousands)	Actual 2010	Projected 2011	Forecast 2012	Forecast 2013
Opening RSDA Balance, net of tax	(3,300)	(35,618)	(52,066)	(53,668)
Annual (Surplus)/ Deficiency	(44,743)	(20,970)	4	17,436
Add: Interest on Balance	(457)	(1,408)	(2,140)	(2,338)
Less: Tax	12,882	5,930	534	(3,775)
Closing RSDA Balance, net of tax	**(35,618)**	**(52,066)**	**(53,668)**	**(42,344)**
Tax Rate	28.5%	26.5%	25.0%	25.0%
Closing RSDA Balance, before tax	**(49,816)**	**(70,838)**	**(71,557)**	**(56,459)**

4.4 When interest is added on the RSDA Balance, what rate of interest is being used?

Response:

The interest rates being used to calculate the forecast RSDA interest for 2012 and 2013 are the FEVI short-term debt rates forecast in the Application (Exhibit B-1) of 4.25 percent and 5.25 percent respectively.

4.5 Are the RSDA funds essentially used to defer financing for the FEU?

Response:

The RSDA is a non-rate base deferral account that is unique to FEVI. As explained on page 72 of the Application (Exhibit B-1), the RSDA captures differences between net revenues received and actual cost of service, excluding O&M variances from forecast.

In determining actual cost of service, FEVI includes a cost of capital that is in accordance with the approved capital structure. FEVI incurs interest expense on the RSDA at rates that are equivalent to the unfunded debt rate (short term debt rate). This interest expense is included in FEVI's actual cost of service and is credited to the RSDA deferral account in favour of the customer. In this fashion, the RSDA deferral becomes a source of financing that is provided by the customer rather than the bank.

4.6 What is the AFUDC rate expected to be for 2012 and 2013?

Response:

The forecast AFUDC rates for FEVI are 6.44 percent in 2012 and 6.56 percent in 2013.

> As discussed in Section 1.2.5, using the existing low cost of gas as the base case, the future rate impacts expected for Vancouver Island are still in the range of a 20 percent increase over the next several years. This impact will be magnified, and may be doubled, should increases in the cost of gas occur. Therefore, FEVI believes that it is appropriate to maintain a rate freeze for 2012 and 2013 and preserve the RSDA mechanism to mitigate future rate increases for our customers.

4.7 When considering a policy of a rate freeze for FEVI was consideration given to providing for a moderate level of rate increase instead of a rate freeze?

Response:

No, providing for a moderate level of rate increase was not considered. Since the rates are equal to the cost of service in 2012 and in anticipation of the Amalgamation and Rate Design Application to be filed in the Fall of 2011 to be effective 2013, FEVI considered a rate freeze to be appropriate at this time.

4.8 Please provide any analysis of alternatives to a rate freeze which may have been prepared by FEVI.

Response:

Please refer to CEC IR 1.4.7.

4.9 Has FEVI considered dropping the costs of hedging from FEVI and instead providing for self-hedging funding through a continuation of the RSDA?

Response:

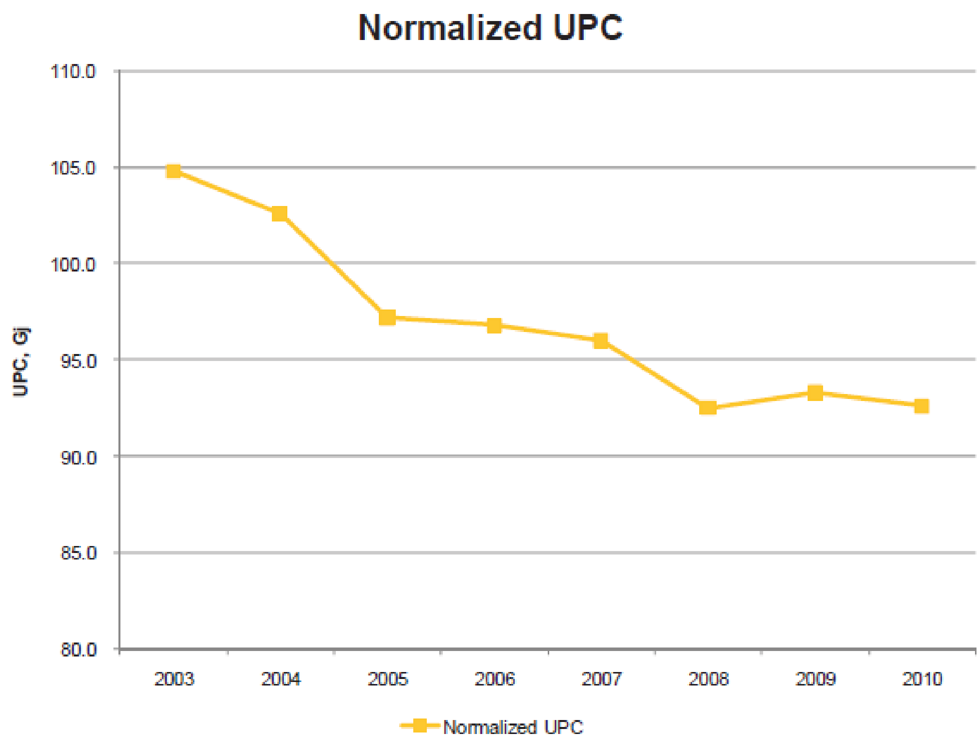
FEVI has interpreted this question to mean has FEVI considered using the RSDA and excluding the use of hedging in mitigating future rate increases for customers. The FEU have evaluated the option of eliminating hedging and using rate smoothing deferral account mechanisms in the context of developing their price/risk management plans and have rejected the idea. Given that determination, FEVI did not consider excluding the use of hedging in mitigating future rate increases for customers and solely relying on the RSDA.

The reason lies in the difference between hedging and the RSDA. The RSDA is the mechanism which captures the difference between the incurred cost of service (including gas cost purchase volume variances, but excluding gas cost price variances which are captured in the GCVA, and variances in O&M), and revenues recovered through rates charged to customers. Neither the RSDA nor the GCVA directly impact the underlying market prices which affect gas costs; any adverse market price movements will be captured in the GCVA and would erode the overall GCVA and RSDA surplus balance if it was to be used to offset increases in the market price of natural gas.

However, hedging does directly impact market prices which affect gas costs by converting floating, or market index prices, to fixed prices. Thus, once hedges are in place, if market prices move adversely, the impact on the GCVA balance will be significantly reduced. This helps to preserve the overall GCVA and RSDA surplus, and mitigate future rate increases for customers.

5. Reference: Exhibit B-1, Page 82

Figure 4.3-2: Normalized Use Rate Per Customer



5.1 Please provide the calculations used by the FEU for the projected UPC declines.

Response:

The data shown in Figure 4.3-2 is the consolidated residential UPC for the Mainland region, calculated by combining monthly UPC data from the four sub-regions: Lower Mainland, Inland, Columbia and Revelstoke. All data presented in Figure 4.3-2 are normalized actual UPC values and no projections are included. The historic data shows a declining trend in UPC in the Mainland region.

Similarly, the forecast UPC for Mainland (see Figure 4.4-2, page 93 of the Application, Exhibit B-1) is the combined monthly UPC data aggregation of the same four sub-regions. The forecast UPC is derived through trending analysis (see the response to BCOAPO IR 1.20.1).

As shown, a declining UPC trend is present in the historic residential rate schedule. The Companies believes the trend will continue over the forecast period.

The following example illustrates the calculation of UPC for Mainland Rate Schedule 1.

Mainland Rate 1 Consolidated UPC 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	
Customers													
LML	524,979	525,212	525,417	525,520	525,706	525,888	526,034	526,246	526,695	527,457	528,512	529,194	
INL	207,685	207,688	207,726	207,517	207,549	207,508	207,467	207,575	207,945	208,638	209,323	209,556	
COL	20,279	20,273	20,265	20,255	20,260	20,245	20,248	20,300	20,345	20,373	20,455	20,490	
RSK	1,321	1,319	1,318	1,314	1,310	1,304	1,313	1,310	1,316	1,318	1,321	1,319	
Mainland	**754,264**	**754,492**	**754,726**	**754,606**	**754,825**	**754,945**	**755,062**	**755,431**	**756,301**	**757,786**	**759,611**	**760,559**	
Consumption (GJ)													
LML	8,154,918	6,665,769	6,151,669	4,362,122	2,696,167	1,785,533	1,506,235	1,535,872	1,851,264	3,799,918	6,005,473	8,038,955	
INL	2,598,625	2,210,273	1,893,104	1,147,019	610,631	399,696	399,274	357,980	520,903	1,197,712	1,874,430	2,544,706	
COL	265,099	221,563	195,509	131,444	81,566	49,273	36,907	35,169	57,157	131,537	195,490	263,996	
RSK	13,546	11,199	11,556	4,791	1,859	1,459	885	940	2,307	5,045	4,559	9,931	
Mainland	**11,032,188**	**9,108,804**	**8,251,838**	**5,645,375**	**3,390,224**	**2,235,961**	**1,943,301**	**1,929,961**	**2,431,632**	**5,134,212**	**8,079,952**	**10,857,588**	
UPC (PJ)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**2010**
Mainland	**14.6**	**12.1**	**10.9**	**7.5**	**4.5**	**3.0**	**2.6**	**2.6**	**3.2**	**6.8**	**10.6**	**14.3**	**92.6**

5.2 The decline in normalized UPC appears to have leveled out over the last couple of years why would it not be reasonable to be forecasting a flat UPC rather than a declining UPC.

Response:

Consistent with past practice, the UPC forecast methodology considers changes in normalized UPC experienced in the last three years, back to 2007.

Specifically for Mainland Rate Schedule 1, the methodology considers 2007, 2008, 2009 and 2010. Over this time period the average normalized actual UPC dropped from 96 to 92.6, an average annual decline of 1.1 GJ/yr.

For the forecast period we are forecasting a decline of 0.9 GJ/yr per year. This reduction does represent a slight levelling of the UPC.

5.3 Please confirm that the FEU do not have a model of the causes of the UPC decline but simply use approximate projection of the declining trend.

Response:

The FEU confirm that we do not have a model of the causes of the UPC decline. In the past the FEU have been unsuccessful in establishing formal quantitative relationships between consumption and external factors such as Canada/US exchange rate, consumer price index (CPI), mortgage rates and unemployment rates.

The FEU confirm that, except for weather[2], all causes are assumed to be implicit in the recent historic data.

Analysis of normalized short-term historic data gives us an accurate overall picture of "what" happened. While the data is unable to tell us "why" it happened, this methodology is appropriate for short-term forecasting.

5.4 Please confirm that the factors potentially influencing the UPC are as follows or add to the list; (a) replacement of older less efficient appliances with more efficient units (b) upgrades to more efficient windows, doors and building shells (c) availability of rebates, funding subsidies or efficiency & conservation funding (d) natural gas pricing (e) government taxation policy (HST & Carbon Tax) (f) the state of the economy (g) competing fuel pricing.

<u>Response:</u>

The FEU confirm that the list of factors provided in the question could all potentially affect the average UPC. In addition, the following factors may potentially impact UPC:

- Changes to the appliances installed and used within the home for heating, hot water, cooking, and decorative (fireplaces);
- Behaviour changes by the people within the home;
- Single family/multi-family housing type mix;
- BC Governmental Policy that all new homes built after January 2009 must put in a gas furnace with efficiency level of 90 percent or higher[3]; and
- Changes to building codes.

There may also be additional factors of greater or lesser significance.

Except for weather, the short term UPC forecast methodology does not attempt to consider these (or any other) factor(s) independently. For the purpose of the short term forecast all

[2] The historic data is weather normalized to remove the affect of annual temperature variances.
[3] The BC Building Code was amended to read "Effective January 1, 2009 All gas-fired forced air furnaces (natural gas and propane) must have an Annual Fuel Utilization Efficiency (AFUE) of at least 90%."

factors are considered implicit in the historic actual data. This methodology is consistent with past practices and has historically provided good results.

5.5 Please confirm that the addition of lower usage accounts to the total would by itself bring down the average UPC without requiring there to be a decline in the average usage.

Response:

FEI confirms that the addition of lower usage accounts to the total would by itself bring down the average UPC without requiring there to be a decline in the average UPC of the already existing customers. However, it would be required that the average usage of all new customers was below the average usage of existing customers.

For example, if there are currently 1,000 customers with an average usage of 100 GJs per year and 100 new customers were added that had an average usage of 75 GJs per year then total UPC would be:

1000 customers x 100GJ = total demand of 100,000GJ

100 customers x 75GJ = total demand of 7,500GJ

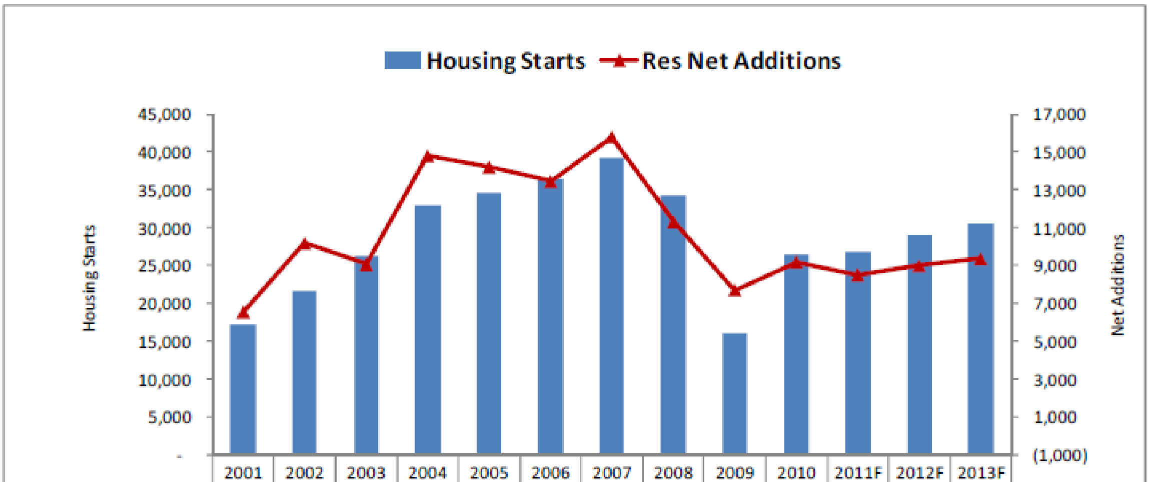
100,000GJ + 7,500GJ = 107,500GJ

105,000GJ/1100 customers = 97.7GJ

In this example the average UPC has declined from 100 GJ to 97.7 GJ even though the UPC for the existing customer base (100 GJ) has not declined.

6. Reference: Exhibit B-1, Page 84

Figure 4.3-3: Customer Additions Correlate Well with Housing Starts for All Companies



	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

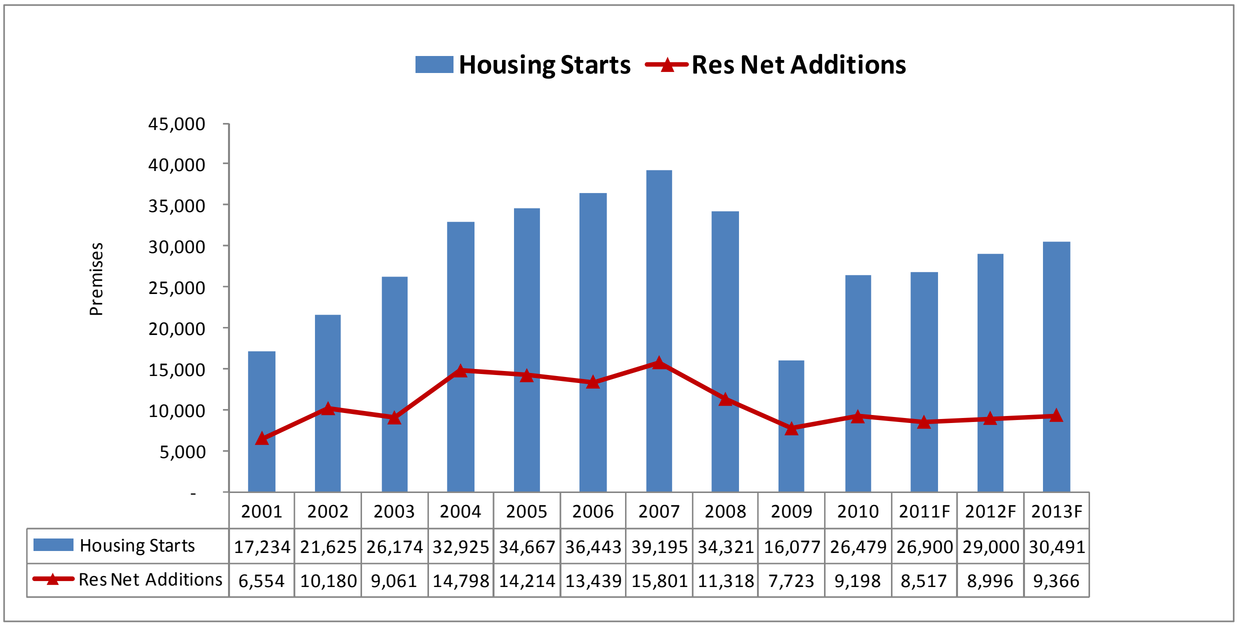
6.1 With the correlation of housing starts and residential net additions, being so close why would the FEU forecast residential net additions lower than housing starts for the test period.

<u>Response:</u>

The FEU do not capture 100 percent of housing starts. Figure 4.3-3 shows the housing starts forecast on the left side "Y" axis and the FEU net additions on the right side "Y" axis.

The choice of scales for the two plots has resulted in the data lying at points very close to one another and this was done to show the strong correlation.

For clarity the same chart is shown using a single Y axis:



	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

In the above chart it is clear that the FEU capture rate does not approach the housing starts count.

6.2 Please provide the impact on the FEU revenue of a 20% and 25% increase in the net residential additions.

Response:

Increasing the net residential additions by 20 percent per year for 2011, 2012 and 2013 would result in a total of 5,374 additional customers by the end of 2013. The increase in revenue would be less than ½ a percent in 2013 and total revenue over the period would increase by 0.28 percent, as shown in Table 1.

Increasing the net residential additions by 25 percent per year for 2011, 2012 and 2013 would result in a total of 6,720 additional customers by the end of 2013. The increase in revenue would reach 0.60 percent in 2013 and total revenue over the period would increase by 0.36 percent, as shown in Table 2.

Table 1

*Impact on Accounts, Volume and Revenue of a **20%** increase in Residential Accounts*

Line No.	Particulars	Change in EOY Accounts	Change in Volume (TJ)	RRA Application ($000)	Revenue Forecast ($000)	Change in Revenue ($000)	Percent Change in Revenue	Column **(4)** Cross Reference
	(1)	(2)	(3)	**(4)**	(5)	(6)	(7)	(8)
1	**2011**							
2	FEI	1,233	52.1	$ 750,208	$ 750,760	$ 552	0.07%	- Sect. 7-TAB 7.1, Schedule 10
3	FEVI	466	10.9	77,516	77,699	183	0.24%	- Sect. 7-TAB 7.2, Schedule 10
4	FEW	3	0.1	3,733	3,735	2	0.05%	- Sect. 7-TAB 7.3, Schedule 10
5	FEFN	1	0.0	2,143	2,142	1	0.04%	- Sect. 7-TAB 7.4, Schedule 10
6	FEU	1,703	63.1	$ 833,599	$ 834,335	$ 738	0.09%	
7								
8	**2012**							
9	FEI	2,534	167.0	$ 750,035	$ 751,818	$ 1,783	0.24%	- Sect. 7-TAB 7.1, Schedule 11
10	FEVI	958	33.7	2,149	2,150	1	0.06%	- Sect. 7-TAB 7.2, Schedule 11
11	FEW	6	0.4	77,040	77,608	569	0.74%	- Sect. 7-TAB 7.3, Schedule 11
12	FEFN	4	0.2	3,833	3,840	6	0.16%	- Sect. 7-TAB 7.4, Schedule 11
13	FEU	3,502	201.3	$ 833,057	$ 835,416	$ 2,359	0.28%	
14								
15	**2013**							
16	FEI	3,889	285.2	$ 750,275	$ 753,329	$ 3,054	0.41%	- Sect. 7-TAB 7.1, Schedule 12
17	FEVI	1,471	56.0	2,157	2,161	4	0.18%	- Sect. 7-TAB 7.2, Schedule 12
18	FEW	8	0.7	76,657	77,606	949	1.24%	- Sect. 7-TAB 7.3, Schedule 12
19	FEFN	6	0.5	3,939	3,950	11	0.28%	- Sect. 7-TAB 7.4, Schedule 12
20	FEU	5,374	342.4	$ 833,027	$ 837,045	$ 4,018	0.48%	
21								
22	3 Year Impact			**$ 2,499,683**	**$ 2,506,796**	**$ 7,114**	**0.28%**	

Table 2

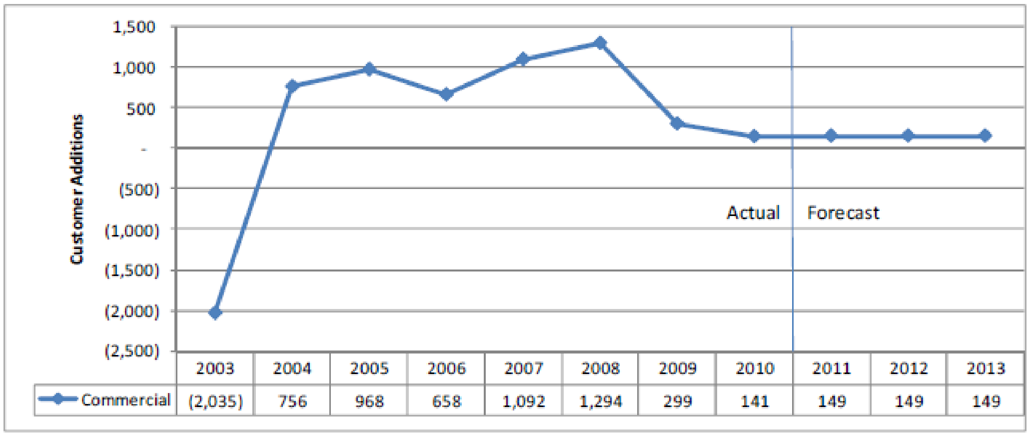
*Impact on Accounts, Volume and Revenue of a **25%** increase in Residential Accounts*

Line No.	Particulars	Change in EOY Accounts	Change in Volume (TJ)	RRA Application ($000)	Revenue Forecast ($000)	Change in Revenue ($000)	Percent Change in Revenue	Column **(4)** Cross Reference
	(1)	(2)	(3)	**(4)**	(5)	(6)	(7)	(8)
1	**2011**							
2	FEI	1,541	65.2	$ 750,208	$ 750,898	$ 690	0.09%	- Sect. 7-TAB 7.1, Schedule 10
3	FEVI	582	13.6	77,516	77,745	229	0.30%	- Sect. 7-TAB 7.2, Schedule 10
4	FEW	4	0.1	3,733	3,735	2	0.06%	- Sect. 7-TAB 7.3, Schedule 10
5	FEFN	3	0.1	2,143	2,143	0	0.02%	- Sect. 7-TAB 7.4, Schedule 10
6	FEU	2,130	79.0	$ 833,599	$ 834,521	$ 921	0.11%	
7								
8	**2012**							
9	FEI	3,168	208.7	$ 750,035	$ 752,264	$ 2,229	0.30%	- Sect. 7-TAB 7.1, Schedule 11
10	FEVI	1,198	42.2	2,149	2,152	3	0.14%	- Sect. 7-TAB 7.2, Schedule 11
11	FEW	7	0.5	77,040	77,751	711	0.92%	- Sect. 7-TAB 7.3, Schedule 11
12	FEFN	6	0.4	3,833	3,841	8	0.20%	- Sect. 7-TAB 7.4, Schedule 11
13	FEU	4,379	251.8	$ 833,057	$ 836,007	$ 2,950	0.35%	
14								
15	**2013**							
16	FEI	4,862	356.5	$ 750,275	$ 754,092	$ 3,818	0.51%	- Sect. 7-TAB 7.1, Schedule 12
17	FEVI	1,838	70.0	2,157	2,163	6	0.29%	- Sect. 7-TAB 7.2, Schedule 12
18	FEW	11	0.9	76,657	77,843	1,186	1.55%	- Sect. 7-TAB 7.3, Schedule 12
19	FEFN	9	0.8	3,939	3,953	14	0.35%	- Sect. 7-TAB 7.4, Schedule 12
20	FEU	6,720	428.2	$ 833,027	$ 838,051	$ 5,024	0.60%	
21								
22	3 Year Impact			**$ 2,499,683**	**$ 2,508,579**	**$ 8,895**	**0.36%**	

Please also refer to the responses to BCOAPO IRs 1.6.2 and 1.19.2 which discuss the revenue requirement impact of variations in customer additions.

7. Reference: Exhibit B-1, Page 97

Figure 4.4-8: Mainland - Forecast Commercial Customers Additions



7.1 Please confirm that a rebound in the economy could be expected to result in increasing commercial activity, including additions of accounts.

Response:

Intuitively a rebound in the economy could be expected to result in an increase in commercial activity. If this were to occur the results would be captured in our actual annual data and then reflected in future forecasts.

As shown net commercial customer additions peaked in 2008 at 1,294. However a sharp decline was observed in 2009 followed by a further decrease in 2010 to 141 net additions. For the forecast period we increased the forecast customer additions slightly to 149 per year.

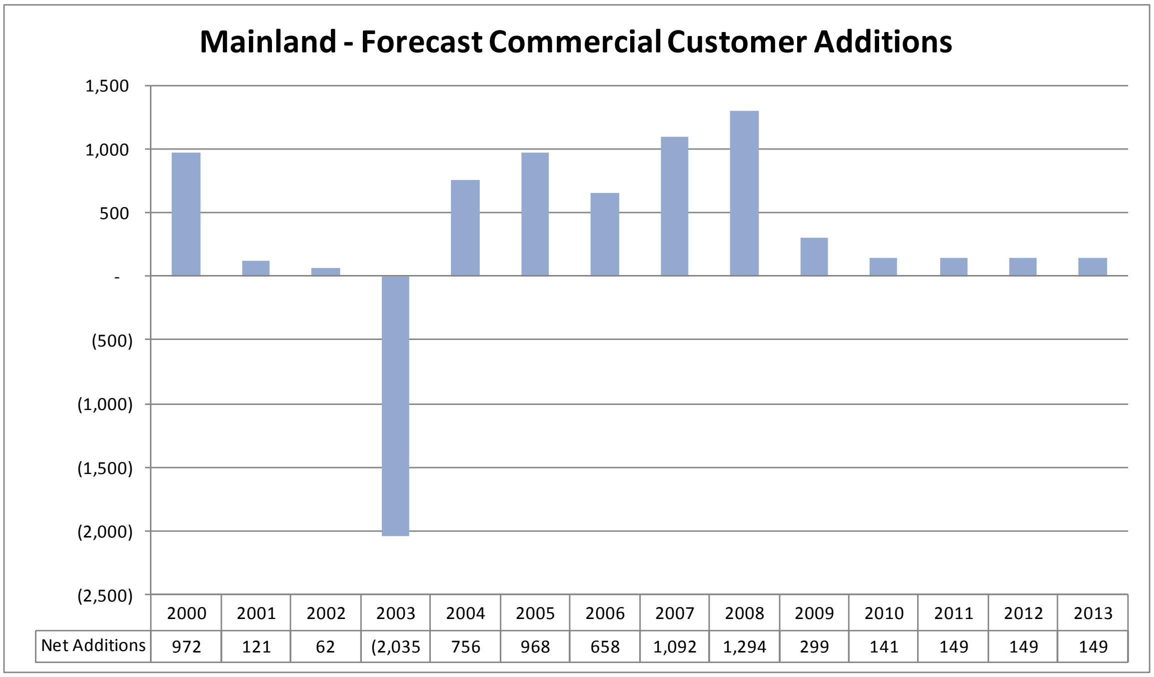
Consistent with past practices the customer additions forecast is developed through the consideration of recent regional and rate class trends in our actual historic data.

7.2 Please confirm that after the 2001 recession the commercial accounts additions dipped in the following years followed by a rebound.

Response:

The FEU confirm that net commercial additions declined in 2001, 2002 and 2003 followed by an increase in 2004. During the recessionary period of 2001-2002 the net commercial additions were 121 and 62 respectively.

The following figure extends Figure 4.4-8 back to 2000.



7.3 Please confirm that the BC economy is rebounding and is forecast to continue rebounding from the 2008/2009 recession.

<u>Response:</u>

Many organizations believe that the BC economy is rebounding from the 2008/2009 recession. However, there are many measures and opinions that each need to be considered to formulate an opinion on BC's current and future economic state.

The overall state and direction of the BC economy is not a direct input into the Companies' forecast model. Rather, our forecast methodology considers the recent history to develop the short-term forecast.

8. Reference: Exhibit B-1, Page 135 & Page 140

The Price Risk Management Plans satisfy the primary objectives of reducing market price volatility and resultant rate volatility for customers. Price Risk Management Plans further serve to improve the likelihood of gas remaining competitive with other sources of energy in order to retain and attract customers.

Reference: Exhibit B-1, Page 135

8.1 Please provide all of the cost of price risk management plans by year including separate disclosure of any carry forward of deferred losses on hedging into the 2012 – 2013 revenue requirements. (Similar to information supplied for Vancouver Island below)

Table 5.2-2: Vancouver Island 2011-2013 Cost of Gas Excluding Royalty Revenues and GCVA Impacts

	Amounts in $ Thousands		
	2011 Projected	2012 Forecast	2013 Forecast
Commodity	$ 38,841	$ 46,828	$ 51,919
Transportation Demand Charges	7,451	8,173	7,584
Storage Demand Charges	3,457	3,499	3,432
Hedging Cost / (Gain)	16,394	15,174	12,786
Gas Supply Management Costs	630	663	678
Total Cost of Gas	$ 66,773	$ 74,337	$ 76,399

Reference: Exhibit B-1, Page 140

Response:

The costs related to price risk management plans for Vancouver Island for 2011 to 2013 are presented as 'Hedging Cost/(Gain)' in Table 5.2-2 of the Application (Exhibit B-1). These represent the projected and forecast direct costs for hedges in place at the time the FEVI 2011 First Quarter Report on the GCVA and RSDA was filed with the Commission and which used the five-day average forward market prices ending February 22, 2011 (e.g. February 15, 16, 17, 18, and 22). For the 2011 projected hedging costs this includes the actual incurred hedging costs for January and the projected hedging costs based on mark-to-market values for February to December. For 2012 and 2013, the hedging costs are forecast based on the mark-to-market values based on the five-day average forward market prices ending February 22, 2011.

The projected and forecast hedging costs resulting from price risk management plans for Mainland, Whistler and Fort Nelson for 2011 to 2013 are presented below. As was done for

Vancouver Island, the hedging costs for Mainland, Whistler, and Fort Nelson are based on the 2011 First Quarter Gas Cost Reports filed with the Commission and which used the five–day average forward market prices ending February 22, 2011. For 2011, this includes the actual incurred hedging costs for January and projected hedging costs based on mark-to-market values for February to December. For 2012, the hedging costs are forecast based on the mark-to-market values as of February 22, 2011. As of February 22, 2011 there were no hedges in place for 2013.

	Amounts in $ Thousands		
	2011 Projected	2012 Forecast	2013 Forecast
Hedging Cost/(Gain)	$ 103,339	$ 30,668	$ 0

8.2 Please provide an analysis of hedging costs splitting the costs between costs to be incurred versus costs which have already been incurred.

Response:

As of the 2011 FEVI First Quarter Report on the GCVA and RSDA the gas costs were determined using the five-day average forward market prices ending February 22, 2011 (e.g. February 15, 16, 17, 18, and 22), and only January 2011 hedging costs would have been incurred. The remaining hedging costs for the months after January 2011 would not yet have been incurred and were based on mark-to-market values at the time. As such, the hedging costs (or gains) for the months after January 2011 will change as market prices change over time. The incurred hedging costs for January 2011, included in the projected hedging costs for 2011 per Table 5.2-2 for Vancouver Island and per the response to CEC IR 1.8.1, are as follows.

	Amounts in $ Thousands		
	2011 Incurred	2011 Projected	2011 Total
Hedging Cost/(Gain)	$ 1,754	$ 14,640	$ 16,394

The incurred hedging costs for January 2011, included in the projected hedging costs for 2011 for Mainland, Whistler and Ft. Nelson and per the response to CEC IR 1.8.1, are as follows.

	Amounts in $ Thousands		
	2011 Incurred	2011 Projected	2011 Total
Hedging Cost/(Gain)	$ 14,576	$ 88,763	$ 103,339

9. Reference: Exhibit B-1, Page 165

Distribution O&M

	O&M Costs				O&M Employees			
	2010	2011	2012	2013	2010	2011	2012	2013
Mainland	41887	43153	47638	51058	519	571	577	586
		3%	10%	7%		10%	1%	2%
Vancouver Island	5238	5379	5787	6369	72	82	79	79
		3%	8%	10%		14%	-4%	0%
Whistler	383	451	430	430	1	2	2	2
		18%	-5%	0%		100%	0%	0%
Ft Nelson	338	347	344	350	3	3	3	3
		3%	-1%	2%		0%	0%	0%

9.1 The above data was taken from tables supplied by FEU. Please confirm that this data is correct and that the percentage change calculations are correct.

Response:

The O&M cost data taken from the Application and displayed in the preamble to the question is correct and is confirmed in the table provided below.

The O&M Employee data however that is displayed in the table in the preamble to the question is not correct. The preamble used the count for all Distribution employees, instead of the count that limited employees to those related to O&M only. The table below provides the correct O&M Employee data, as well as percentage change calculations.

Table CEC IR1.9.1 - Distribution O&M and Employee Count

	O&M in $000s				O&M Employees			
	2010 Approved	**2011** Projected	**2012** Forecast	**2013** Forecast	**2010** Approved	**2011** Projected	**2012** Forecast	**2013** Forecast
Mainland	41,887	43,153	47,638	51,058	367	370	382	389
% Change		3%	10%	7%		1%	3%	2%
Vancouver Island	5,238	5,379	5,787	6,369	41	38	38	38
% Change		3%	8%	10%		-7%	0%	0%
Whistler	383	451	430	430	1	2	2	2
% Change		18%	-5%	0%		100%	0%	0%
Ft. Nelson	338	347	344	350	3	3	3	3
% Change		3%	-1%	2%		0%	0%	0%

9.2 The data seems to point to an increasing cost per employee well beyond what might be expected for normal operating circumstances. Please confirm the following cost per employee calculations and provide explanations as to why such significant increases have been planned.

	O&M Cost/Employee			
	2010	2011	2012	2013
Mainland	80.7	75.6	82.6	87.1
		-6%	9%	6%
Vancouver Island	72.8	65.6	73.3	80.6
		-10%	12%	10%
Whistler	383.0	225.5	215.0	215.0
		-41%	-5%	0%
Ft Nelson	112.7	115.7	114.7	116.7
		3%	-1%	2%

Response:

The O&M Employee data that is displayed in the table in the preamble to the question is not correct. The preamble used the count for all Distribution employees, instead of the count that limited employees to those O&M related only. The table below provides the correct O&M cost per employee, as well as percentage change calculations.

Table CEC IR1.9.2 - Distribution O&M per Employee

O&M per FTE in $ Thousands

	2010 Approved	2011 Projected	2012 Forecast	2013 Forecast
Mainland	114.1	116.6	124.7	131.3
% Change		2%	7%	5%
Vancouver Island	127.8	141.6	152.3	167.6
% Change		11%	8%	10%
Whistler	383.0	225.5	215.0	215.0
% Change		-41%	-5%	0%
Ft. Nelson	112.7	115.7	114.7	116.7
% Change		3%	-1%	2%

The Mainland Distribution O&M costs for 2012 are forecast to be approximately $4.5 million higher than projected costs in 2011 and $3.4 million higher in 2013 compared to 2012. The increases are summarized by category in Section 5.3.5.7 of the Application (Exhibit B-1), specifically Table 5.3 -17, page 171. The detailed information for each category is provided on pages 172-177.

In addition to inflation, several of the requested items in 2012 and 2013 have been budgeted as non-internal labour (contractors, consultants, materials). In 2012 and 2013, these include NGV and bio-methane operating and maintenance, battery upgrades (partially materials, partially internal labour), bridge crossing repairs, IT licensing costs, system sustainment assessments and vehicle and non-labour inflation. All other things being equal, the inclusion of these incremental non-internal labour items in the Application, without a corresponding internal O&M headcount, increase the Distribution O&M per Employee ratio.

The Vancouver Island Distribution O&M costs for 2012 are forecast to be approximately $0.4 million higher than projected costs in 2011 and $0.6 million higher in 2013 compared to 2012. The increases are summarized by category in Section 5.3.5.8 of the Application (Exhibit B-1), specifically Table 5.3 -18, page 177. The detailed information for each category is provided on page 177.

In addition to inflation, the requested increases include non-internal labour items (contractors, materials) for a lock standardization program and a major bridge crossing repair. All other things being equal, the inclusion of these incremental non-internal labour items in the Application, without a corresponding internal O&M headcount, increase the Distribution O&M per Employee ratio.

9.3 Did 2011 represent 2011 operational amalgamation constraint on costs?

Response:

Please refer to the responses to CEC IRs 1.9.1 and 1.9.2 for correct O&M Employee data and Distribution O&M per Employee ratios respectively.

No, 2011 did not represent operational amalgamation constraint on costs.

The Mainland Distribution projected O&M for 2011, an increase of 3 percent from 2010, is primarily inflation but also includes incremental items for 2011 offset by reductions in 2010 items.

The Vancouver Island Distribution projected O&M for 2011, an increase of 3 percent from 2010, is primarily inflation but also includes incremental items for 2011 offset by reductions in 2010 items.

9.4 Does the plan for 2012 and 2013 represent giving back cost efficiency achieved earlier?

Response:

Refer to the responses to CEC IRs 1.9.1 and 1.9.2 for correct O&M Employee data and Distribution O&M per Employee ratios, respectively.

The 2012-2013 Distribution O&M request is based on a zero-based budgeting approach which factors in cost efficiencies achieved in prior years, elimination of one-time non-recurring budget items, inclusion of new incremental one-time and recurring items, changes to existing budget items and inflationary adjustments.

For example, in the 2011 Vancouver Island Distribution O&M, FEVI reduced the first response standby cost budget by $350 thousand which effectively continues with the 2012-2013 forecast.

10. Reference: Exhibit B-1, Page 179 & 180

Transmission O&M

	O&M Costs				O&M Employees			
	2010	2011	2012	2013	2010	2011	2012	2013
Mainland	13871	14994	16280	17499	53	55	59	60
		8%	9%	7%		4%	7%	2%
Van. Island	4542	6134	6755	7064	28	31	33	34
		35%	10%	5%		11%	6%	3%

10.1 Please ensure that this data taken from the application is correct and that the percentage change calculations are correct.

Response:

The O&M cost data taken from the Application and displayed in the table to the preamble to the question is correct and is confirmed in the table provided below.

The O&M Employee data however that is displayed in the table to the preamble to the question is not correct. The preamble used the count for all Transmission employees, instead of the count that limited employees to those O&M related only. The table below provides the correct O&M Employee data, as well as percentage change calculations.

Table CEC IR1.10.1 - Transmission O&M and Employee Count

	O&M in $000s				O&M Employees			
	2010 Approved	**2011** Projected	**2012** Forecast	**2013** Forecast	**2010** Approved	**2011** Projected	**2012** Forecast	**2013** Forecast
Mainland	13,871	14,994	16,280	17,499	53	50	53	54
% Change		8%	9%	7%		-6%	6%	2%
Vancouver Island	4,542	6,134	6,755	7,064	28	31	33	34
% Change		35%	10%	5%		11%	6%	3%

10.2 Please explain the dramatic increase in costs for Vancouver Island in 2011.

Response:

The Vancouver Island Transmission O&M costs for 2011 are projected to be approximately $1.6 million higher than actual costs incurred in 2010. This increase is driven primarily by the placement of Mt. Hayes into service in 2011. This change is responsible for approximately $1.3

million in incremental costs, of which $900 thousand relates to new employees hired as plant manager and operators and the remaining $400 thousand for general plant operations.

The remaining incremental O&M is comprised of general inflation on labour and materials, and cost changes as a result of the need to meet codes and regulations, some of which are non-recurring and act to offset the overall increase.

10.3 Please confirm that the 'cost per employee' calculations shown below are correct.

	O&M Cost/Employee			
	2010	2011	2012	2013
Mainland	261.7	272.6	275.9	291.7
		4%	1%	6%
Vancouver Island	162.2	197.9	204.7	207.8
		22%	3%	1%

Response:

Not confirmed, the O&M Cost per Employee data shown above is incorrect. The O&M Employee data that is displayed in the table to the preamble to the question is not correct as it shows the count for all Transmission employees, instead of the count that limited employees to those O&M related only. The table below uses the correct O&M Employee data that is required to calculate the O&M cost per employee, as well as percentage change calculations.

Table CEC IR1.10.3 - Transmission O&M per Employee

O&M per FTE in $ Thousands

	2010 Approved	2011 Projected	2012 Forecast	2013 Forecast
Mainland	261.7	299.9	307.2	324.1
% Change		15%	2%	5%
Vancouver Island	162.2	197.9	204.7	207.8
% Change		22%	3%	1%

10.4 Please explain the increase in cost per employee for Vancouver Island in 2011.

Response:

Please refer to the response to CEC IR 1.10.2 where FEVI discusses that only part of the 2011 increase in costs related to the Mt. Hayes LNG Facility is employee-related, with the remainder due to general plant operating costs.

11. Reference: Exhibit B-1, Page 188

Table 5.3-25: Energy Supply & Resource Development O&M Requirements to Meet Future Obligations

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 3,325	$ 3,251	$ 3,748	$ 3,748	$ 3,943	$ 4,196
Vancouver Island	$ -	$ -	$ 100	$ 100	$ 100	$ 100
Whistler			$ -	$ -	$ -	$ -
Fort Nelson						
Total	$ 3,325	$ 3,251	$ 3,848	$ 3,848	$ 4,043	$ 4,296

11.1 Please identify if any of these O&M costs are related to CMAE staffing or whether these costs match the net staffing levels shown.

Response:

The Energy Supply & Resource Development O&M costs set out in Table 5.3-25 do not include any costs related to CMAE for CMAE staffing levels. The O&M costs set out in Table 5.3-25 match the Net O&M employee count line item set out in Table 5.3-26 on page 188 of the Application (Exhibit B-1).

Table 5.3-26: Energy Supply & Resource Development Employees Required to Meet Future Obligations

Total Employees

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	42	40	42	45	46	47
Vancouver Island	0	0	0	0	0	0
Whistler	0	0	0	0	0	0
Fort Nelson	0	0	0	0	0	0
Total	42	40	42	45	46	47
Less: CMAE	(21)	(20)	(21)	(22)	(22)	(22)
Net O&M	21	20	21	23	24	25

11.2 Please provide the costs that match the CMAE staffing levels shown.

Response:

The CMAE costs that match the CMAE staffing levels shown in the preamble above (Table 5.3-26 of the Application, Exhibit B-1, Page 188) are set out in Table 5.2-3: CMAE Forecast in Exhibit B-1, Page 142. CMAE costs are managed separately from the Companies' O&M budget and are instead managed as part of the cost of gas.

12. Reference: Exhibit B-1, Page 254

Table 5.3-68: Corporate O&M for the Forecast Period

Amounts in $ Thousands

Utility/Region	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Mainland	$ 11,274	$ 13,915	$ 11,201	$ 11,201	$ 7,266	$ 7,424
Vancouver Island	$ 11,057	$ 10,506	$ 11,065	$ 11,065	$ 12,625	$ 12,522
Whistler	$ 251	$ 264	$ 261	$ 261	$ 330	$ 331
Fort Nelson*	$ 317	$ 321	$ 329	$ 329	$ 522	$ 547
Total	$ 22,898	$ 25,007	$ 22,856	$ 22,856	$ 20,743	$ 20,824

** Following the in-sourcing of the customer service function in 2012, the 2011 approved Fort Nelson Customer Service O&M of $136 thousand was transferred to the Corporate department. This approach recognizes that customer service costs are captured in FEI and then allocated to Fort Nelson in a manner which is consistent with other FEI departments' allocated costs, in the Corporate department.*

12.1 Please explain why the total Corporate O&M costs have decreased from 2011.

Response:

Total Corporate O&M costs in 2012 reflect a decrease of $2.1 million from 2011. This decrease is explained on pages 262 – 266 of the Application (Exhibit B-1). Excluding variances in Shared Service Fees/Recoveries which net to zero on an amalgamated basis, the decrease in Corporate O&M in 2012 can be summarized as follows:

FEI

- $(2.8) million decrease in Past Service Pension and OPEB expense as described on page 150 of the Application
- $1.1 million increase in Corporate Service fees from FHI
- $0.1 million increase in support costs

FEVI

- $(0.7) million decrease in Past Service Pension and OPEB expense as described on page 150 of the Application
- $0.1 million increase in insurance expense
- $0.1 million increase in support costs

Total Corporate O&M costs in 2013 reflect an increase of $0.1 million from 2012. This increase is explained on pages 262 – 266 of the Application (Exhibit B-1). Excluding variances in Shared Service Fees/Recoveries which net to zero on an amalgamated basis, the increase in Corporate O&M in 2013 can be summarized as follows:

FEI

- $(0.5) million decrease in Past Service Pension and OPEB expense as described on page 150 of the Application
- $0.3 million increase in Corporate Service fees from FHI
- $0.2 million increase in insurance costs

FEVI

- $0.1 million increase in insurance and support expenses

12.2 Please explain why Vancouver Island uses more Corporate O&M than the Mainland.

Response:

The higher Corporate O&M on Vancouver Island is primarily due to the accounting presentation for Shared Service fees. From an accounting perspective, allocation of shared services from the Mainland, all else equal, results in a higher Corporate O&M for Vancouver Island (receiver of allocation increases O&M) compared to Mainland Corporate OM (sender of allocation reduces O&M).

The Mainland recovers Shared Service fees from Vancouver Island and Whistler, as well as making internal allocations to recognize recoveries for Shared Services provided to Thermal Energy Services and CMAE. The Shared Service fee that the Mainland recovers extends beyond that of Corporate expenses to include the full spectrum of operational support that is provided by the Mainland.

Please see page 273 of the Application (Exhibit B-1) for a listing of the common services delivered on a Shared Service basis. Although the Shared Service fees/recoveries are operational in nature, they are reflected in the Corporate department.

Using 2012 Forecast as an example, FEI's Shared Service recoveries total $11.6 million and show as an offset to Corporate O&M whereas Vancouver Island's Shared Service fee of $9.6 million shows as an increase to Corporate O&M.

For this reason, on a net basis, Mainland Corporate O&M is lower than Vancouver Island.

12.3 Please explain whether the FEU have any strategy or plan to reduce the Corporate O&M for Vancouver Island.

Response:

Please see the response to CEC IR 1.12.2.

The FEU believe that the proposed Corporate O&M for Vancouver Island is reasonable and prudent. The sharing of resources under a Shared Services agreement has enabled the Companies and its customers to realize the benefits of economies of scale by having a single management and support structure.

13. Reference: Exhibit B-1, Page 292

Table 5.5-1: Forecast Other Revenue for 2012 and 2013[97]

($thousands) Utility/Region	Approved 2011	Forecast 2012	Forecast 2013
Mainland	$ 24,394	$ 27,203	$ 28,883
Vancouver Island	9,752	12,651	12,662
Whistler	56	16	16
Fort Nelson	60	24	24
Total	**$ 34,262**	**$ 39,894**	**$ 41,585**

13.1 Please confirm that the primary drivers for these projected increases in other revenue are from CNG/LNG Services.

Response:

The primary drivers for Mainland and Vancouver Island forecasted Other Revenue increases are from CNG/LNG Service and LNG Mitigation Revenues, respectively, as illustrated below.

Mainland
($Thousands)

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2	Late Payment Charge	$ 3,020	$ 2,333	$ 2,333	$ (687)	$ (687)
3	Connection Charge	2,907	2,662	2,685	(245)	(222)
4	NSF Returned Cheque Charges	82	79	79	(3)	(3)
5	Other Recoveries	76	122	126	46	50
6						
7	Total Other Utility Revenue	6,085	5,196	5,223	(889)	(862)
8						
9	**Miscellaneous Revenue**					
10	FEVI Wheeling Charge	3,455	3,456	3,464	$ 1	$ 9
11	SCP Third Party Revenue	14,798	14,852	14,827	54	29
12	FEVI SAP Lease Income	56	17	-	(39)	(56)
13	Biomethane Other Revenue	-	(62)	(29)	(62)	(29)
14	CNG & LNG Service Revenues	-	3,744	5,398	3,744	5,398
15						
16	Total Miscellaneous	18,309	22,007	23,660	3,698	5,351
17						
18	**Total Other Operating Revenue**	$ 24,394	$ 27,203	$ 28,883	$ 2,809	$ 4,489

FEVI
($Thousands)

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2	Late Payment Charge	$ 345	$ 223	$ 224	$ (122)	$ (121)
3	Connection Charge	380	399	409	19	29
4	NSF Returned Cheque Charges	5	3		(2)	(5)
5	Other Recoveries	2	-	3	(2)	1
6						
7	**Total Other Utility Revenue**	732	625	636	(107)	(96)
8						
9	**Miscellaneous**					
10	LNG Mitigation Revenue from FEI	9,020	12,026	12,026	3,006	3,006
11						
12	Total Miscellaneous	9,020	12,026	12,026	3,006	3,006
13						
14	**Total Other Operating Revenue**	$ 9,752	$ 12,651	$ 12,662	$ 2,899	$ 2,910

13.2 Please identify the drivers for the balance of the increase.

Response:

Please refer to the tables below which identify the changes in Other Revenue for each Utility for 2012 and 2013:

Mainland

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2	Late Payment Charge	$ 3,020	$ 2,333	$ 2,333	$ (687)	$ (687)
3	Connection Charge	2,907	2,662	2,685	(245)	(222)
4	NSF Returned Cheque Charges	82	79	79	(3)	(3)
5	Other Recoveries	76	122	126	46	50
6						
7	Total Other Utility Revenue	6,085	5,196	5,223	(889)	(862)
8						
9	**Miscellaneous Revenue**					
10	FEVI Wheeling Charge	3,455	3,456	3,464	$ 1	$ 9
11	SCP Third Party Revenue	14,798	14,852	14,827	54	29
12	FEVI SAP Lease Income	56	17	-	(39)	(56)
13	Biomethane Other Revenue	-	(62)	(29)	(62)	(29)
14	CNG & LNG Service Revenues	-	3,744	5,398	3,744	5,398
15						
16	Total Miscellaneous	18,309	22,007	23,660	3,698	5,351
17						
18	**Total Other Operating Revenue**	$ 24,394	$ 27,203	$ 28,883	$ 2,809	$ 4,489

FEVI

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2	Late Payment Charge	$ 345	$ 223	$ 224	$ (122)	$ (121)
3	Connection Charge	380	399	409	19	29
4	NSF Returned Cheque Charges	5	3		(2)	(5)
5	Other Recoveries	2	-	3	(2)	1
6						
7	**Total Other Utility Revenue**	732	625	636	(107)	(96)
8						
9	**Miscellaneous**					
10	LNG Mitigation Revenue from FEI	9,020	12,026	12,026	3,006	3,006
11						
12	Total Miscellaneous	9,020	12,026	12,026	3,006	3,006
13						
14	**Total Other Operating Revenue**	$ 9,752	$ 12,651	$ 12,662	$ 2,899	$ 2,910

FEW

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 49	$ 11	$ 11	$ (38)	$ (38)
4	Connection Charge	5	4	4	(1)	(1)
5	NSF Returned Cheque Charges	-	-	-	-	-
6	Other Recoveries	2	1	1	(1)	(1)
7						
8	**Total Other Utility Revenue**	$ 56	$ 16	$ 16	$ (40)	$ (40)

Fort Nelson

Line No.	Particulars	2011 Approved	2012 Forecast	2013 Forecast	2012 Increase	2013 Increase
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 38	$ 13	$ 13	$ (25)	$ (25)
4	Connection Charge	20	11	11	(9)	(9)
5	Other Recoveries	2			(2)	(2)
6						
7	**Total Other Utility Revenue**	$ 60	$ 24	$ 24	$ (36)	$ (36)

13.3 Please elaborate on what could be done to increase the performance in generating additional other revenue over the forecast period.

Response:

Aside from FEVI Wheeling Revenue, SCP Third Party Revenue, and CNG & LNG Service Revenue, the other revenue is miscellaneous ancillary revenue that recovers costs that the utility has incurred. These are incidental to the utilities' operations and not the focus of our primary service of delivering energy to customer premises.

In future revenue requirement applications, FEI anticipates that the revenues from the CNG & LNG service will be included in the Sales and Revenue Schedules instead of being forecast as Other Revenue.

The FEU, through the Business Development and other departments, continue to explore service opportunities that can be economically offered that would be beneficial to all stakeholders.

14. Reference: Exhibit B-1, Page 309

> FEI obtains short term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the issuance of commercial paper by maintaining a $500 million committed credit facility, which matures August 2013. FEVI obtains its short term funding through advances made available on its $300 million committed credit facility. The credit facilities provide the Companies with crucial liquidity should there be constraints in the capital markets that make obtaining cost-effective financing for working capital and debt issuance requirements temporarily unavailable. FEW obtains its financing from FHI.

14.1 Please confirm that as a matter of policy the FEU short term debt is limited to this credit facility and that the FEU as a matter of policy fund capital with long term debt when cash flows require that such financing be issues, within the flexibility provided by this short term facility.

Response:

Confirmed. In general terms, the long-term debt and short-term debt combined provide the 60 percent debt funding of rate base that is required by the approved capital structure of the FEU. The majority of the FEU's funding requirements are met through the issuance of long and medium-term debt. Short-term credit facilities are relied upon mainly to provide liquidity during short-term fluctuations of working capital, and to fund capital expenditures between issuances of long-term debt. The FEU's short-term debt is limited to a $500 million committed credit facility for FEI and a $300 million committed credit facility for FEVI.

15. Reference: Exhibit B-1, Page 318

Table 6.1-2: Mainland Rate Base 2011 through 2013[110]

($ thousands) **Mainland**	**Approved 2011**	**Forecast 2012**	**Forecast 2013**
Mid Year Net Plant In Service	$ 2,494,713	$ 2,555,445	$ 2,634,300
Adjustment to 13-month average	-	40,567	-
Work in progress, no AFUDC	15,627	17,110	17,110
	2,510,340	2,613,122	2,651,410
Deferred Charges	6,770	27,407	38,574
Cash Working Capital	(6,534)	(3,445)	(1,963)
Gas In Storage Working Capital	114,804	97,294	97,242
Other Working Capital	5,287	3,611	4,380
Other	(1,482)	(1,482)	(1,316)
Utility Rate Base	**$ 2,629,185**	**$ 2,736,507**	**$ 2,788,327**

15.1 Please explain the adjustment to a 13 month average.

Response:

Please refer to BCUC IR 1.89.1.

15.2 Please explain the components involved in the Work in Progress.

Response:

As per the BCUC Uniform Code of Accounts, work in progress (referred as Gas Plant Under Construction in the Code of Accounts) has the following components and attributes which FEI follows.

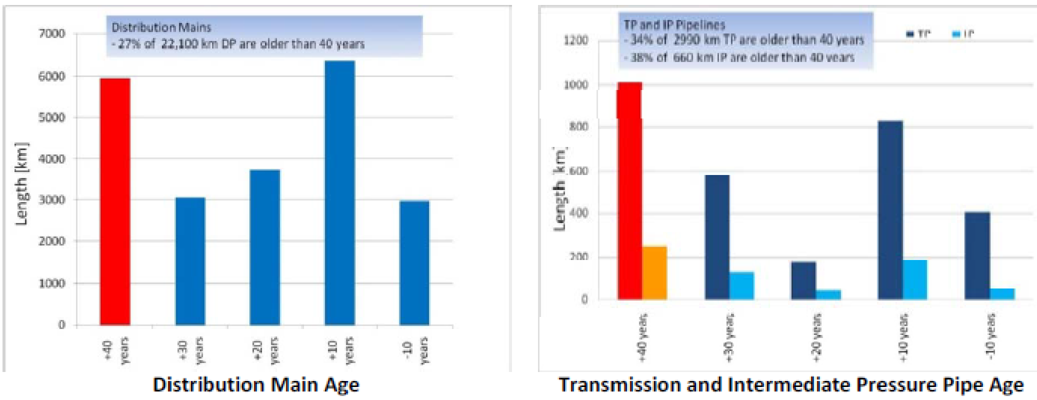
"This account shall include the cost of construction of gas plant, not completed or ready for service at the date of balance sheet, including the cost of land acquired for such projects ... and of unapplied construction material and supplies located at point of use or held in inventory for the construction of new equipment and/or extensions. It shall also

include taxes during construction and other elements of cost of such construction work. When any plant, the cost of construction of which has been included in this account, is completed and ready for service the cost thereof shall be credited to this account and charged to the primary plant accounts appropriate to the character of the plant."

The amount of work in progress included in rate base excludes those project costs that are or will be subject to AFUDC.

16. Reference: Exhibit B-1, Page 337

Figure 6.2-1: Proportions of Transmission and Distribution Approaching Retirement



(+10 years means more than / -10 years means less than)

16.1 Please explain what the FEU are doing and can do to extend the life of the transmission and distribution assets.

Response:

The FEU have a number of asset management programs in place designed to extend or, more accurately, "optimize" the life of the transmission and distribution assets in order to maximize use and minimize lifecycle costs. These programs centre on the use of material standards, work methods and employee skills. They also include such activities as damage prevention, security measures, regular maintenance, cathodic protection, pipeline patrols, natural hazard monitoring, in-line inspections and problem mitigation, pipe and coating condition monitoring and problem mitigation, equipment condition monitoring, and leak surveys.

16.2 Please explain what the FEU are doing or can do to monitor and assess the need for replacement as well as the opportunity for extension to improve on the Iowa Curve experience planning view.

Response:

While the Iowa Curve provides an indication of industry experience of the life expectancy of gas system assets, it does not set a hard target. The FEU will continue to ensure effective programs are in place to maximize the design life and minimize the lifecycle cost of its gas system assets. This work forms the basis for a number of Capital and O&M programs that are outlined in the response to CEC IR 1.16.1.

The FEU have initiated the development and implementation of an improved long-term view of asset management or system sustainment. As experience and skills in this field are developed it will provide additional information that can be used to initiate new, or reinforce existing, programs designed to maximize asset life expectancy and minimize lifecycle cost.

17. Reference: Exhibit B-1, Page 386

Table 6.3-2: Forecast Mid-Year Balances of Deferral Accounts by Category[131]

2012 Forecast, Mid Year Balance, ($ thousands)	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ (9,371)	$ (4,062)	$ 703	$ (41)	$ (12,770)
Energy Policy	27,396	3,163	75	-	30,635
Non-Controllable	(614)	108	(79)	(4)	(589)
Application Costs	1,600	172	147	3	1,921
Other	7,686	(477)	26,761	96	34,065
Residual	711	-	(23)	-	688
Mid Year Balance, Deferral Accounts	**$ 27,407**	**$ (1,096)**	**$ 27,583**	**$ 54**	**$ 53,949**

2013 Forecast, Mid Year Balance, ($ thousands)	Mainland	Vancouver Island	Whistler	Fort Nelson	Total
Margin Related	$ 2,529	$ -	$ 480	$ (7)	$ 3,003
Energy Policy	37,198	4,316	218	-	41,731
Non-Controllable	2,259	35	50	(2)	2,342
Application Costs	986	72	9	1	1,068
Other	(5,082)	(532)	25,947	91	20,423
Residual	684	-	-	-	684
Mid Year Balance, Deferral Accounts	**$ 38,574**	**$ 3,891**	**$ 26,703**	**$ 83**	**$ 69,252**

17.1 Please identify which deferral accounts include overhead charges, if any, and which deferral accounts attract AFUDC, if any.

Response:

While none of the deferral accounts include overhead charges, the accounts below include AFUDC incurred prior to 2012:

- 2010-2011 Biomethane Program Costs
- 2010-2011 Customer Service O&M and COS

The AFUDC was incurred while these deferral accounts were treated as non-rate base before transferring into rate base January 1, 2012.

AFUDC will not be incurred in 2012 or 2013 for any of the rate base deferrals in Table 6.3-2.

17.2 Please provide the policy basis for the inclusion or exclusion as the case may be.

Response:

Please refer to BCOAPO IRs 1.1.3 and 1.1.4 which discuss the policy basis for rate base and non-rate base deferral accounts and principles of rate of return, respectively.

Rate base deferral accounts attract the Commission Approved return on rate base while non-rate base accounts typically attract AFUDC or another form of carrying charge. In both cases the deferral accounts, as identified in CEC IR 1.17.1, are transitioning from non-rate base deferral accounts attracting AFUDC, to rate base deferral accounts attracting the approved return on rate base:

- The 2010-2011 Biomethane Program costs deferral was approved via Commission Order G-194-10 and was to incur AFUDC prior to January 1, 2012, at which time it would be transferred into rate base and no longer incur AFUDC.
- The 2010-2011 Customer Service O&M and COS deferral was approved through Commission Orders C-1-10, G-23-10 and G-141-09 and was to incur AFUDC prior to January 1, 2012, at which time it would be transferred into rate base and no longer incur AFUDC.