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March 2, 2015

**Via Email**  
**Original via Mail**

British Columbia Utilities Commission  
Sixth Floor  
900 Howe Street  
Vancouver, B.C. V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

**Re: FortisBC Energy Inc. (FEI)**

**Multi-Year Performance Based Ratemaking Plan for 2014 through 2019  
approved by British Columbia Utilities Commission Order G-138-14 - Annual  
Review for 2015 Rates**

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

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On January 14, 2015, FEI filed the Application as referenced above. In accordance with Commission Order G-6-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Diane Roy

Attachments

cc (email only): Registered Parties



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1 **A. EVALUATION OF THE PERFORMANCE BASED RATE-MAKING PLAN FOR 2014**

2 **1.0 Reference: LABOUR SAVINGS**

3 **Exhibit B-1, Section 1.4, p. 4**

4 FEI states: "Much of the savings has been associated with labour, which is reflective of a  
5 broad-based, Company-wide effort to seek alternate solutions to the filling of  
6 vacancies."<sup>1</sup>

7 1.1 Did FEI achieve any labour savings due to the reduction of Full Time Equivalent  
8 Employees (FTEs) during 2014? If yes, please indicate the number of FTEs  
9 which were eliminated during 2014.

10

11 **Response:**

12 This response will address BCUC IRs 1.1.1, 1.1.2 and 1.1.3.

13 For FEI, the total number of FTEs declined by 60 for 2014, from 1,570 at the end of 2013 to  
14 1,510 at the end of 2014. Although labour savings were achieved in 2014 as compared to  
15 2013, staffing levels may increase in 2015 as the company prioritizes its spending and fills  
16 positions as required.

17 The number of FTEs for FEI for 2014 do not include the FTEs for FEVI and FEW. At the end of  
18 2014, FEVI had 113 FTEs and FEW had 1 FTE, which when added to the FEI FTEs results in  
19 total FEI Amalgamated FTEs of 1,624.

20

21

22

23 1.2 Please provide the total number of FTEs at the end of 2014 and at the end of  
24 2013.

25

26 **Response:**

27 Please refer to the response to BCUC IR 1.1.1.

28

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<sup>1</sup> Exhibit B-1, p. 4.



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1           1.3    Will FEI experience an increase in FTEs as a result of the amalgamation with  
2                   FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler)  
3                   Inc. (FEW)? If yes, please provide the number of FTEs added to FEI at the time  
4                   of amalgamation. If not, please explain why not.

5  
6    **Response:**

7    Please refer to the response to BCUC IR 1.1.1.

8

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1   **2.0   Reference:   REGIONALIZATION INITIATIVE**

2                           **Exhibit B-1, Section 1.4, p. 4**

3           FEI states on page 4 of the Application:

4                           Contributing to the O&M [Operations and Maintenance] savings in 2014 is FEI's  
5                           Regionalization initiative, which is aimed at both enhancing the customer  
6                           experience and achieving a more efficient process in the field. Throughout 2014,  
7                           Operations moved certain aspects of its centralized operational activities into  
8                           regional locations.<sup>2</sup>

9           2.1   Please explain how regionalizing certain aspects of the Operations department  
10                           and switching from one centralized emergency centre to eight regional  
11                           emergency centres, has created O&M savings. Please specifically describe the  
12                           drivers of these savings and approximately what percentage of these savings is  
13                           associated with labour and with non-labour.

14  
15   **Response:**

16   Regionalization is a customer service initiative. The Regionalization initiative was a component  
17   part of a broader strategy to improve customer service and to create a productivity focus and an  
18   accountability culture among all employees.

19   Throughout the course of 2014, Operations moved certain aspects of its centralized operational  
20   activities into regional locations. Field Dispatch, Planning & Design groups and a regional  
21   engineering position are now located within their regional locations. By having these roles  
22   working closer with operations employees, decision making is quicker, more cost-effective and  
23   is based on more local knowledge to better serve customers in terms of cost, timeliness, and  
24   customer convenience. These changes have also increased autonomy and accountability for  
25   employees who are closest to customers.

26   The regional model is also improving FEI's ability to respond to a certain level of emergencies  
27   and threats, as local resources with local knowledge will be managing these situations. There  
28   are now eight emergency centres around the province rather than one large central emergency  
29   centre.

30   Another key element of FEI's transition to a regional operations model is the dispersion of  
31   supervision across the service territory. These positions are now providing day-to-day  
32   leadership and support to field crews, while bringing decision making and accountability closer  
33   to employees, and providing customers with access to local contacts and services.

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<sup>2</sup> Ibid.



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1 Overall, the regionalization, productivity and accountability initiatives resulted in O&M savings  
2 predominantly in the form of labor savings within Operations.

3 Generally speaking, the following efficiencies were realized:

- 4 • Reduction in overall field delivery operating and capital costs. Supervisors are more  
5 involved in monitoring work flow and employee productivity.
- 6 • Reduction in daytime first response standby costs through improved utilization of  
7 workforce and local assignment of work.
- 8 • Reduction in dispatching costs through improved local oversight.
- 9 • Reduction in planning costs through improved local oversight.
- 10 • Regional engineers are creating a stronger link between field operations and FEI's  
11 centralized engineering and asset management departments to improve optimization  
12 and implementation of the capital program.

13  
14 It is difficult to separate Regionalization savings from the broader initiatives of improving  
15 customer service, enhancing the productivity focus and strengthening the accountability culture.  
16 Also, changes occurred throughout the year and affected multiple cost centres. Overall,  
17 Operation's O&M savings related to the above-noted broader initiatives were approximately  
18 \$1.0 million in 2014.

19  
20

21

22 2.2 What prompted FEI to make the decision to transition from a centralized  
23 operation to a more regionalized operation?

24

25 **Response:**

26 The desire to improve customer service and achieve a more efficient process in the field  
27 prompted FEI to make the decision to transition from a centralized operation to a more  
28 regionalized operation. Regionalization places ownership, responsibility and accountability for  
29 customer service and field processes in the hands of those who are closest to the customers.

30

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1           2.3    Has FEI previously operated under a more regionalized model? If yes, please  
2                    compare the previous regional model to the current Regionalization initiative and  
3                    explain why in the past FEI moved away from a regional model.  
4

5    **Response:**

6    In the late 1990s, FEI operated under a more regionalized model. The previous model included  
7    customer service representatives, dispatchers, drafters, planners, and financial analysts in  
8    various regions across the FEI service territory.

9    FEI moved away from a regional model to facilitate the use of technology and to ensure  
10   standardized processes and procedures were followed across the service territory to reduce  
11   costs and provide better service to customers.

12   The current regionalization initiative repositions dispatchers and some planners in closer  
13   physical proximity to internal and external customers which they support.

14  
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16  
17           2.4    How does the amalgamation of FEI, FEVI and FEW impact the Regionalization  
18                    initiative? For instance, does this initiative create higher costs for FEVI and/or  
19                    FEW which would then reduce future savings for the amalgamated entity?  
20                    Please discuss.  
21

22    **Response:**

23    The amalgamation of the three gas utilities does not impact the Regionalization initiative as the  
24    amalgamation was focused primarily on combining FEI, FEVI and FEW into one legal entity and  
25    being able to offer common rates across the FEI service territory. Additionally, prior to the FEU  
26    amalgamation, the three gas utilities have been operating under one operating model for quite  
27    some time.

28    However, in 2014, the initiative did create higher costs in FEVI due to the repositioning of the  
29    dispatch function. From an FEI amalgamated perspective, the repositioning of the dispatch role  
30    was cost neutral.

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1           2.5     Please describe the potential challenges of moving to a regional operations  
2                     model and how FEI plans to address these challenges.

3  
4     **Response:**

5     As FEI moved to a regional operations model, it experienced challenges with recruitment,  
6     training and process changes. These challenges have all been adequately addressed as  
7     demonstrated by the successful launch of all regional Dispatch Centres in Q2, 2014 and  
8     subsequent regionalization of Planners in the Lower Mainland in Q4, 2014.

9  
10

11

12           2.6     Are there any O&M departments which are anticipated to experience incremental  
13                     annual costs as a result of regionalization? Please discuss.

14

15     **Response:**

16     Some O&M regional departments experienced incremental annual costs while other centralized  
17     departments experienced reduced annual costs. The combined effect of these cost increases  
18     and decreases was net positive. Please refer to the response to BCUC IR 1.2.1.

19  
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21

22           2.7     How many Field Dispatch and Planning and Design groups are there now, and  
23                     where are they located?

24

25     **Response:**

26     There are 8 Field Dispatch Groups located in the following locations;

- 27           1. Burnaby  
28           2. Surrey  
29           3. Victoria  
30           4. Nanaimo  
31           5. Prince George



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1 6. Kamloops

2 7. Kelowna

3 8. Cranbrook

4

5 There are 19 Planning and Design Groups located in the following locations;

6 1. Victoria

7 2. Nanaimo

8 3. North Vancouver

9 4. Burnaby

10 5. Richmond

11 6. Coquitlam

12 7. Surrey

13 8. Chilliwack

14 9. Langley

15 10. Delta

16 11. Abbotsford

17 12. Maple Ridge

18 13. Prince George

19 14. Kamloops

20 15. Vernon

21 16. Kelowna

22 17. Penticton

23 18. Trail

24 19. Cranbrook



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2.8 Please explain the inter-relationship and coordination between the Field Dispatch and Planning and Design groups and the eight regional emergency centres.

**Response:**

During regular business hours, Field Dispatch acts as the regional emergency centre and coordinates FEI's response to all regional emergencies. Outside regular business hours, the Emergency Operations Centre in Surrey acts as the provincial emergency centre and coordinates FEI's response to all emergencies in the province.

Field Dispatch and Planning and Design groups have an indirect coordination relationship. Field Dispatch manages the field resource capacity that the Planning and Design groups allocate to FEI's customer commitments.

2.8.1 Please explain the extent to which these regional groups are sufficiently resourced so as to be reasonably autonomous, and the extent to which they are supported by central operations department resources.

**Response:**

The resourcing level of regional groups was determined and set based on the actual regional work load and the required skillset such that each region would be able to operate reasonably autonomously. The Planning and Design groups continue to be centrally supported with respect to permitting, underground utility information gathering and construction work order closing.

2.8.2 Please discuss the extent to which these regional groups will require incremental capital expenditures, including additional office space, field equipment and communications facilities, and the amount of any incremental expenditures.



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1 **Response:**

2 Please refer to the response to BCUC IR 1.2.9 where FEI shows the capital expenditures  
 3 incurred in 2014, and indicates that no capital expenditures will be required in total or in any of  
 4 the regions in 2015.

5  
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7

8 2.9 Please provide the following information on the Regionalization initiative in  
 9 tabular form with separate columns for each year of the Performance Based  
 10 Rate-Making (PBR) term:

- 11 • A description of the projects expected to be undertaken in each year of the  
 12 PBR and the expected timeline for implementation and completion of each  
 13 project;
- 14 • A description of organizational changes resulting from the implementation of  
 15 each initiative, including whether any departments will experience staffing  
 16 increases/decreases or re-allocations of resources amongst departments;
- 17 • A description and quantification of O&M expenditures expected to be  
 18 incurred;
- 19 • A description and quantification of any capital expenditures which are  
 20 anticipated to be incurred;
- 21 • The amount of anticipated savings expected to be realized in each year of the  
 22 PBR and a description of how and where these savings are expected to be  
 23 achieved, including whether the savings are from labour or non-labour.

24

25 **Response:**

26 The requested table is provided below.

	2014	2015+
<b>Activities undertaken</b>	<ul style="list-style-type: none"> <li>• Operations Supervisor recruitment and training</li> <li>• Dispatcher relocation, recruitment and training</li> <li>• Planner relocations</li> <li>• Process review and modification</li> <li>• IT infrastructure modifications</li> <li>• Facilities modifications</li> </ul>	None



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	2014	2015+
<b>Organizational changes</b>	<ul style="list-style-type: none"><li>• Dispatch staff decreases</li><li>• Operations staff increases due to hiring of Operations Supervisors</li><li>• Operations staff decreases due to retirements and terminations not replaced</li><li>• Planners staff re-allocated to Operations</li></ul>	None
<b>O&amp;M expenditures incurred or expected to be incurred</b>	<b>\$0.9 million</b> This included costs for a number of activities including employee development/ training, IT and facilities.	None
<b>Capital expenditures incurred or expected to be incurred</b>	<b>\$1.3 million</b> This includes costs for IT, facilities and communications.	None
<b>Anticipated savings</b>	Refer to the response to BCUC IR 1.2.1.	Ongoing

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2.10 Did the Regionalization initiative contribute to Actual 2014 capital expenditures being higher than the formula amount? If yes, please provide the amount and describe the purpose of the capital expenditures.

**Response:**

The Regionalization initiative did result in some capital expenditures as shown in the response to BCUC IR 1.2.9. Since FEI's overall capital expenditures were higher than the 2014 formula amount, spending in any category could be characterized as contributing to the variance, as without that spending the total would have been lower.



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1 **3.0 Reference: PROJECT BLUE PENCIL**

2 **Exhibit B-1, Section 1.4, p. 5**

3 On page 5 of the Application, FEI states:

4 Project Blue Pencil is an initiative focused on reviewing and streamlining several  
5 high volume, customer-facing processes from the perspective of the  
6 customer...Specifically, in the areas of new service connections, meter  
7 exchange, collections and high bill inquiry, initiatives are currently underway,  
8 each on a timeline to increase productivity for existing resources in both the  
9 Operations and Customer Service groups during the term of the PBR.<sup>3</sup>

10 3.1 Please elaborate on how FEI plans to achieve operational efficiencies in each of  
11 the areas included in the above preamble.

12 **Response:**

13 The focus of Blue Pencil is to simplify and improve customer-facing processes by finding  
14 opportunities for improvement in internal process. Once areas of improvement were identified,  
15 a new revised process was developed to reduce hand-offs and simplify where possible.  
16 Simplified processes contribute to First Contact Resolution (FCR) and Customer Satisfaction  
17 (CSAT). A byproduct of this simplification of the customer experience is increased productivity  
18 and efficiency.

19 **New Service Connections:**

20 A review of FEI's new service process showed that it was cumbersome and complex for  
21 customers to navigate. When customers called into the contact center, they were asked many  
22 construction-related questions which customers found difficult to answer. As a result, a new  
23 simplified quoting process was put in place to require only five questions to be answered by the  
24 customer. In addition, more autonomy was given to the field resources in determining the most  
25 cost effective design plan in the installation of new services. This reduces planning costs and  
26 involves the customer in the planning process on site more effectively.

27 **Meter Exchange:**

28 Each year, FEI exchanges approximately 70,000 gas meters. Each exchange requires an  
29 appointment with the customer and requires someone to be present at the customers' premise  
30 in order to complete the re-lighting of appliances. The coordination of customer appointments is  
31 a complex task which requires us to balance the availability of the customer with the availability  
32 of field resources to complete the exchange.

33 <sup>3</sup> Exhibit B-1, p. 5.



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1 The improved process has the contact center and operations departments working more closely  
2 together in order to better meet the needs of customers and match resources to appointments.

3 **Collections:**

4 A review of collections practices revealed that the current process was generally effective at  
5 providing good customer service while maintaining low accounts receivable. However, a few  
6 improvement areas were identified, such as matching the hours of work of Collections  
7 Representatives with regular contact center hours to better meet customer needs. Expected  
8 benefits from these changes include improved connection rates on outbound collection calls,  
9 and reduced repeat calls to the contact center.

10 **High Bill Inquiries:**

11 A review of high bill inquiries identified opportunities to improve resolution with the first inquiry  
12 from the customer. It was determined that high bill escalations could be reduced by properly  
13 distinguishing between “high bill” and “payment” concerns. Referring the case to billing or to the  
14 field was determined to add limited value other than a perception of an escalation by the  
15 customer. This same escalation process could be more efficiently handled within the contact  
16 center.

17 In order to address these issues, customer service representatives and management within the  
18 contact center received additional training on high bill resolution, escalation techniques and  
19 improved active listening. Expected benefits from these changes include improved FCR and  
20 CSAT related to high bill calls and reduced costs in the contact center, billing operations and  
21 field operations departments from repeat calls and site visits.

22  
23

24

25 3.2 Please explain how FEI expects cost savings to be realized from streamlining  
26 processes in the above-mentioned areas. In particular, please describe the cost  
27 drivers which FEI plans to target to achieve savings.

28

29 **Response:**

30 Project Blue Pencil initiatives simplify customer-facing processes in order to improve the  
31 customer experience. The new streamlined processes can also result in operational savings by  
32 allowing quicker decision-making at the first point of customer contact and resolving inquiries  
33 without repeated customer interactions for the same issue. Please refer to BCUC IR 1.3.3 for a  
34 discussion of costs savings associated with Project Blue Pencil.



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1 Cost drivers that are impacted by this in the contact center include repeat calls, inbound and  
 2 outbound call volumes and the average handle time of calls. Cost drivers in operations include  
 3 driving time, idle time, planning costs, standardization of service installation and the  
 4 organization of field work.

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8 3.3 Please provide the following information on Project Blue Pencil in tabular form  
 9 with separate columns for each year of the PBR:

- 10 • A description of the projects expected to be undertaken in each year of the  
 11 PBR and the expected timeline for implementation and completion of each  
 12 project;
- 13 • A description of organizational changes resulting from the implementation of  
 14 each project, including whether any departments will experience staffing  
 15 increases/decreases or re allocations of resources amongst departments;
- 16 • A description and quantification of O&M expenditures expected to be  
 17 incurred;
- 18 • A description and quantification of any capital expenditures which are  
 19 anticipated to be incurred;
- 20 • The amount of anticipated savings expected to be realized in each year of the  
 21 PBR and a description of how and where these savings are expected to be  
 22 achieved, including whether the savings are from labour or non-labour.

23

24 **Response:**

25 The Blue Pencil project was an initiative focused on reviewing and streamlining five specific  
 26 processes for the benefit of customers. Although the five processes were reviewed in 2014,  
 27 some changes to the processes have extended into 2015. Savings will begin to occur in 2015  
 28 with some savings being achieved in 2016.

	2014	2015	2016+
Processes Reviewed	High Bill Inquiry		
	Emergency		
	Collections		
	Meter Exchange		
	New Construction		



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	2014	2015	2016+
Organizational Changes	Contact center will experience a FTE reduction as a result.	Contact center will experience a FTE reduction as a result.	Contact center will experience a FTE reduction as a result.
O&M expenditures expected to be incurred	\$0 Incremental O&M costs	\$0 Incremental O&M costs	\$0 Incremental O&M costs
Capital expenditures expected to be incurred	<\$100 thousand	<\$200 thousand	\$0
Annual Savings - Labour	< \$100 thousand	Approximately \$400 thousand in annual contact center O&M savings. Approximately \$100 - \$200 savings in the average cost of a new service installation.	Approximately \$900 thousand in annual contact center O&M savings. Approximately \$100 - \$200 savings in the average cost of a new service installation.
Annual Savings – non-Labour	\$0	\$0.	\$0

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3.4 Does FEI anticipate that any of the O&M departments/groups will experience annual cost increases due to these initiatives (compared to the expected savings in the Operations and Customer Service department)? Please discuss.

**Response:**

At this time, the changes to processes being implemented through the Blue Pencil project are not expected to result in cost increases for other groups..

3.5 Please discuss how the Project Blue Pencil initiative relates to the establishment of regional Field Dispatch and Planning and Design groups and regional emergency centres.



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1 **Response:**

2 Project Blue Pencil is not related to the establishment of the Regionalization initiative. However,  
3 as both were occurring at the same time, the teams worked together to ensure new simplified  
4 and customer focused processes were designed within the framework of the regionalized  
5 model.

6  
7

8  
9 3.6 Please discuss the extent to which Project Blue Pencil will require incremental  
10 capital expenditures, including additional office space, and IT and other facilities,  
11 and provide the amount of any additional capital expenditures.

12  
13 **Response:**

14 Please refer to the response to BCUC IR 1.3.3.

15  
16

17  
18 3.7 What impact, if any, is Project Blue Pencil expected to have on capital  
19 expenditures for new service connections and meter exchanges?

20  
21 **Response:**

22 Please refer to the response to BCUC IR 1.3.3.

23  
24

25  
26 3.7.1 Please discuss whether Project Blue Pencil and other initiatives are  
27 expected to reduce the cost of a service line addition on Vancouver  
28 Island or in Whistler to bring the cost in these areas closer to the  
29 average cost on the Mainland.

30  
31 **Response:**

32 Project Blue Pencil and other initiatives are expected to reduce the cost of a service line  
33 addition for the entire FEI service territory, including Vancouver Island and Whistler. However,



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1 as the changes are in the early stages, it is not possible to determine at this time the reduction  
2 of the cost of a service line addition on Vancouver Island or in Whistler relative to the average  
3 cost on the Mainland.

4



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1 **B. FORMULA DRIVERS**

2 **4.0 Reference: INFLATION FACTOR**

3 **Exhibit B-1, Section 2.1, p. 9**

4 **Inflation adjustment**

5 FEI states on pages 9-10 of the Application:

6 To correct for the impact of the transition from HST [Harmonized Sales Tax] to  
7 PST [Provincial Sales Tax] in the calculation, 9/12ths of the annual adjustment  
8 factor must be considered. Since the annual impact of the transition to PST on  
9 CPI [Consumer Price Index] is estimated to be 0.700 percent, the 2015 impact is  
10 0.530 percent (0.700% X 9/12 = 0.530%).<sup>4</sup>

11 4.1 Please confirm, or explain otherwise, that when rounded to three decimal places,  
12 the 2015 impact is 0.525 percent, not 0.530 percent.

13

14 **Response:**

15 Confirmed.

16

17

18

19 4.2 Please confirm, or explain otherwise, that as part of the Commission's  
20 acceptance of FEI's PBR Compliance Filing for 2014 rates, the Commission  
21 requested that FEI adopt a standard of using numbers with three decimal places  
22 for presentation and calculation purposes.

23

24 **Response:**

25 The scope of the Commission's request in FEI's PBR Compliance Filing was unclear to FEI. In  
26 an effort to further understand, FEI contacted Commission Staff and was advised that this  
27 request was to ensure alignment between the financial schedules and any tables provided in the  
28 body of the Application. Accordingly, FEI has provided financial schedules in thousands of  
29 dollars and has expanded all tables in the Application that are in millions of dollars to three  
30 decimal places to facilitate reconciliation between the detail financial schedules and any tables.

31 In the circumstance of the adjustment to CPI noted in the question preamble, the figure used  
32 should have included three decimal places to align with the 2014 adjustment. This change

---

<sup>4</sup> Exhibit B-1, pp. 9-10



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1 results in minor reductions of approximately \$5 thousand to formula O&M and approximately \$3  
2 thousand to formula capital expenditures and does not impact the delivery rates in 2015. FEI will  
3 update its calculated I-Factor to reflect a 0.525 percent adjustment to CPI for the PST impact  
4 when it files its Compliance filing for final 2015 delivery rates.

5  
6

7

8 4.2.1 If confirmed, please revise the 2015 inflation impact to be 0.525 percent  
9 for presentation and calculation purposes. Please also revise any  
10 numbers/calculations which have changed as a result of using 0.525  
11 percent.

12

13 **Response:**

14 Please refer to the response to BCUC IR 1.4.2.

15



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1 **C. DEMAND FORECAST**

2 **5.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES**

3 **Exhibit B-1: Section 3, pp. 14-25; Section 11, Schedule 4, p. 70;**  
 4 **Appendix A3**

5 **Demand Forecast Data**

6 5.1 For each service area (Mainland, Vancouver Island, and Whistler), please use  
 7 the template below to produce four tables in a functional excel spreadsheet, as  
 8 well as hard copy versions, providing information for each year from 2009 to  
 9 2015 for:

- 10 i. Year-End Customer Account Totals
- 11 ii. Annual Customer Additions
- 12 iii. Average Normalized Use Per Customer
- 13 iv. Total Normalized Energy Demand.

14 Under the customer class heading please include all the rate schedules and  
 15 customer classes as seen in Schedule 4 in Section 11 of the Application.  
 16  
 17

	Column 1	Column 2	Column 3	Column 4	...	Column 9
Line 1	<b>Customer Class</b>		<b>2009</b>	<b>2010</b>	<b>...</b>	<b>2015</b>
Line 2	RS 1	Actual				
Line 3		Forecast				
Line 4		Variance (units)				
Line 5		Variance (%)				
Line 6	RS 2	Actual				
Line 7		Forecast				
Line 8		Variance (units)				
Line 9		Variance (%)				
...	...	Actual				
		Forecast				
		Variance (units)				
		Variance (%)				

18  
 19  
 20 **Response:**

21 This IR requests a significant amount of data that FEI was unable to compile within the timeline  
 22 for responding to IRs. In order to respond to this IR in the time provided, FEI has used  
 23 information filed in its Annual Reports to the Commission. The information in the Annual



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1 Reports does not report on each rate schedule individually, but groups the rate schedules by  
2 customer class. For example, for FEI the information is compiled as follows:

- 3 • Residential (Rate Schedule 1)
- 4 • Commercial (Rate Schedule 2 and 3)
- 5 • Small Industrial/Seasonal (Rate Schedule 4, 5, 7 and 16)
- 6 • Commercial (Rate Schedule 23)
- 7 • Small Industrial (Rate Schedule 25 and 27)
- 8 • Large Industrial (Rate Schedule 22, 22A and 22B)
- 9 • NGV (Rate Schedules 6)

10  
11 FEI believes it is reasonable to group the data by customer class in this fashion as the rate  
12 schedules in each customer class share similar characteristics. However, if the Commission  
13 requires the further detail on each rate schedule, FEI is prepared to compile the data upon  
14 request.

15 The IR also requests information for Mainland, Vancouver Island and Whistler and that FEI  
16 “include all the rate schedules and customer classes as seen in Schedule 4 in Section 11 of the  
17 Application”. The referenced rate schedules are common rate schedules that were  
18 implemented January 1, 2015 for Vancouver Island and Whistler. FEI was unable to  
19 retroactively restate the FEVI and FEW forecast demand based on the common rate schedules  
20 for 2009 to 2014. Similarly, FEI was unable to calculate the Vancouver Island and Whistler  
21 2015 forecast using the pre-existing FEVI and FEW rate schedules. FEI has therefore provided  
22 the information for FEVI and FEW based on FEVI and FEW’s rate schedules as they existed  
23 from 2009 to 2014, and has only shown rate schedule 1 for the 2015 forecast for FEVI and FEW  
24 because that was the only rate schedule that remained unchanged with the adoption of common  
25 rates. Please refer to Attachment 5.1 for the fully functioning Excel file.



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### Mainland: Year-End Customer Account Totals

Mainland		2009	2010	2011	2012	2013	2014	2015
Customer Class	Customer Accounts							
<b>Residential (Rate 1)</b>	Actual YE Customer Account Totals	753,735	760,559	765,553	759,712	766,668	774,083	
	Forecast Customer Account totals	755,803	757,161	765,610	773,231	780,005	768,622	780,972
	Variance (units)	2,068	(3,398)	57	13,519	13,337	(5,461)	
	Variance (%)	0%	0%	0%	2%	2%	-1%	
<b>Commercial (Rate 2 &amp; 3)</b>	Actual YE Customer Account Totals	80,827	80,910	81,300	76,910	78,078	79,089	
	Forecast Customer Account totals	80,400	82,287	82,363	81,088	81,177	77,499	79,876
	Variance (units)	(427)	1,377	1,063	4,178	3,099	(1,590)	
	Variance (%)	-1%	2%	1%	5%	4%	-2%	
<b>Small Industrial/ Seasonal (Rate 4, 5, 7 &amp; 16)</b>	Actual YE Customer Account Totals	288	244	231	233	227	224	
	Forecast Customer Account totals	287	290	271	247	247	230	224
	Variance (units)	(1)	46	40	14	20	6	
	Variance (%)	0%	19%	17%	6%	9%	3%	
<b>Commercial (Rate 23)</b>	Actual YE Customer Account Totals	1,348	1,406	1,433	1,520	1,529	1,522	
	Forecast Customer Account totals	1,426	1,319	1,366	1,526	1,586	1,634	1,552
	Variance (units)	78	(87)	(67)	6	57	112	
	Variance (%)	6%	-6%	-5%	0%	4%	7%	
<b>Small Industrial (Rate 25 &amp; 27)</b>	Actual YE Customer Account Totals	703	658	608	606	593	641	
	Forecast Customer Account totals	686	678	657	658	658	588	641
	Variance (units)	(17)	20	49	52	65	(53)	
	Variance (%)	-2%	3%	8%	9%	11%	-8%	
<b>Large Industrial (Rate 22, 22A &amp; 22B)</b>	Actual YE Customer Account Totals	45	43	43	46	45	46	
	Forecast Customer Account totals	47	45	45	43	43	45	46
	Variance (units)	2	2	2	(3)	(2)	(1)	
	Variance (%)	4%	5%	5%	-7%	-4%	-2%	
<b>NGV (Rate 6)</b>	Actual YE Customer Account Totals	29	24	20	16	12	15	
	Forecast Customer Account totals	32	32	32	21	21	14	15
	Variance (units)	3	8	12	5	9	(1)	
	Variance (%)	10%	33%	60%	31%	75%	-7%	

2

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1

### Mainland: Annual Customer Additions

Mainland		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Customer Additions</b>							
<b>Residential (Rate 1)</b>	Actual Annual Customer Additions	4,822	6,824	4,994	4,475	6,956	7,415	
	Forecast Customer Additions	6,410	5,129	6,021	6,507	6,774	4,594	6,889
	Variance (units)	1,588	(1,695)	1,027	2,032	(182)	(2,821)	
	Variance (%)	33%	-25%	21%	45%	-3%	-38%	
<b>Commercial (Rate 2 &amp; 3)</b>	Actual Annual Customer Additions	257	83	390	181	1,168	1,011	
	Forecast Customer Additions	487	814	790	89	89	331	787
	Variance (units)	230	731	400	(92)	(1,079)	(680)	
	Variance (%)	90%	880%	103%	-51%	-92%	-67%	
<b>Small Industrial/ Seasonal (Rate 4,5,7 &amp; 16)</b>	Actual Annual Customer Additions	(19)	(44)	(13)	4	(6)	(3)	
	Forecast Customer Additions	-	-	-	-	-	-	0
	Variance (units)	19	44	13	(4)	6	3	
	Variance (%)	n/a	n/a	n/a	n/a	n/a	n/a	
<b>Commercial (Rate 23)</b>	Actual Annual Customer Additions	42	58	27	88	9	(7)	
	Forecast Customer Additions	53	9	9	60	60	57	30
	Variance (units)	11	(49)	(18)	(28)	51	64	
	Variance (%)	26%	-84%	-67%	-32%	567%	-914%	
<b>Small Industrial (Rate 25 &amp; 27)</b>	Actual Annual Customer Additions	(2)	(45)	(50)	(1)	(13)	48	
	Forecast Customer Additions	1	-	-	-	-	-	0
	Variance (units)	3	45	50	1	13	(48)	
	Variance (%)	-150%	n/a	n/a	n/a	n/a	n/a	
<b>Large Industrial (Rate 22, 22A &amp; 22B)</b>	Actual Annual Customer Additions	(7)	(2)	-	3	(1)	1	
	Forecast Customer Additions	(1)	-	-	-	-	-	0
	Variance (units)	6	2	-	(3)	1	(1)	
	Variance (%)	-86%	n/a	n/a	n/a	n/a	n/a	
<b>NGV (Rate 6)</b>	Actual Annual Customer Additions	(3)	(5)	(4)	(3)	(4)	3	
	Forecast Customer Additions	-	-	-	-	-	-	0
	Variance (units)	3	5	4	3	4	(3)	
	Variance (%)	n/a	n/a	n/a	n/a	n/a	n/a	

2



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1

### Mainland: Average Normalized Use Per Customer

Mainland		2009	2010	2011	2012	2013	2014	2015
Customer Class	Average Normalized Use per Customer (GJ/yr)							
<b>Residential (Rate 1)</b>	Actual Average Normalized UPC	93	93	91	92	89		
	Forecast Average Normalized UPC	91	92	90	91	90	91	86
	Variance (units)	(2)	(1)	(0)	(2)	1		
	Variance (%)	-2%	-1%	0%	-2%	1%		
<b>Commercial (Rate 2 &amp; 3)</b>	Actual Average Normalized UPC	507	497	504	537	522		
	Forecast Average Normalized UPC	461	505	507	493	491	537	517
	Variance (units)	(46)	9	3	(44)	(31)		
	Variance (%)	-9%	2%	1%	-8%	-6%		
<b>Small Industrial/Seasonal (Rate 4, 5, 7 &amp; 16)</b>	Actual Average Normalized UPC	10,776	9,925	11,124	11,105	11,361		
	Forecast Average Normalized UPC	10,072	11,344	11,345	10,076	10,089	10,374	10,634
	Variance (units)	(704)	1,419	221	(1,029)	(1,272)		
	Variance (%)	-7%	14%	2%	-9%	-11%		
<b>Commercial (Rate 23)</b>	Actual Average Normalized UPC	4,882	4,861	5,127	5,248	5,142		
	Forecast Average Normalized UPC	4,424	4,686	4,687	4,949	4,974	5,546	5,309
	Variance (units)	(459)	(175)	(441)	(299)	(168)		
	Variance (%)	-9%	-4%	-9%	-6%	-3%		
<b>Small Industrial (Rate 25 &amp; 27)</b>	Actual Average Normalized UPC	27,357	27,762	30,327	30,238	31,843		
	Forecast Average Normalized UPC	25,695	28,621	28,621	29,199	29,295	30,831	29,971
	Variance (units)	(1,662)	859	(1,706)	(1,039)	(2,548)		
	Variance (%)	-6%	3%	-6%	-3%	-8%		
<b>Small Industrial - Total (Rate 23, 25, 27, 4, 5, 7, &amp; 16)</b>	Actual Average Normalized UPC	12,342	12,156	12,806	12,557	12,764		
	Forecast Average Normalized UPC	11,313	12,656	12,625	12,267	12,129	12,380	12,317
	Variance (units)	(1,030)	499	(181)	(290)	(636)		
	Variance (%)	-8%	4%	-1%	-2%	-5%		
<b>NGV (Rate 6)</b>	Actual Average Normalized UPC	3,074	2,440	3,450	3,647	3,571		
	Forecast Average Normalized UPC	3,125	3,244	3,250	2,686	2,686	3,663	3,179
	Variance (units)	51	804	(200)	(961)	(886)		
	Variance (%)	2%	33%	-6%	-26%	-25%		

2

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### Mainland: Total Normalized Energy Demand

Mainland								
Customer Class	Sales Volumes (TJ)	2009	2010	2011	2012	2013	2014	2015
<b>Residential (Rate 1)</b>	Actual Total Normalized Energy Demand	69,999	70,041	68,933	69,753	68,089		
	Forecast Total Normalized Energy Demand	68,497	69,174	68,579	69,890	69,816	69,512	67,207
	Variance (units)	(1,502)	(867)	(354)	137	1,727		
	Variance (%)	-2%	-1%	-1%	0%	3%		
<b>Commercial (Rate 2 &amp; 3)</b>	Actual Total Normalized Energy Demand	40,716	40,013	40,761	41,063	40,207		
	Forecast Total Normalized Energy Demand	36,886	41,193	41,771	39,908	39,847	41,500	41,092
	Variance (units)	(3,830)	1,180	1,010	(1,155)	(360)		
	Variance (%)	-9%	3%	2%	-3%	-1%		
<b>Small Industrial/Seasonal (Rate 4, 5, 7 &amp; 16)</b>	Actual Total Normalized Energy Demand	3,168	2,660	2,870	2,743	2,738		
	Forecast Total Normalized Energy Demand	3,092	3,392	3,392	2,604	2,607	2,482	2,480
	Variance (units)	(76)	732	522	(139)	(131)		
	Variance (%)	-2%	28%	18%	-5%	-5%		
<b>NGV (Rate 6)</b>	Actual Total Normalized Energy Demand	83	61	69	62	50		
	Forecast Total Normalized Energy Demand	100	104	104	56	56	51	48
	Variance (units)	17	43	35	(6)	6		
	Variance (%)	20%	70%	51%	-10%	12%		
Customer Class	Transportation Volumes (TJ)	2009	2010	2011	2012	2013	2014	2015
<b>Commercial (Rate 23)</b>	Actual Total Normalized Energy Demand	6,469	6,630	7,373	7,803	7,867		
	Forecast Total Normalized Energy Demand	6,109	6,134	6,177	7,151	7,485	8,721	8,255
	Variance (units)	(360)	(496)	(1,196)	(652)	(382)		
	Variance (%)	-6%	-7%	-16%	-8%	-5%		
<b>Small Industrial (Rate 25 &amp; 27)</b>	Actual Total Normalized Energy Demand	18,849	18,767	19,864	19,201	20,029		
	Forecast Total Normalized Energy Demand	17,678	19,405	19,405	19,213	19,276	18,684	19,211
	Variance (units)	(1,171)	638	(459)	12	(753)		
	Variance (%)	-6%	3%	-2%	0%	-4%		
<b>Large Industrial (Rate 22, 22A &amp; 22B)</b>	Actual Total Normalized Energy Demand	26,324	30,050	34,943	38,037	36,401		
	Forecast Total Normalized Energy Demand	27,725	27,117	27,117	29,675	29,620	35,118	33,340
	Variance (units)	1,401	(2,933)	(7,826)	(8,362)	(6,781)		
	Variance (%)	5%	-10%	-22%	-22%	-19%		

2

3

### Vancouver Island: Year-End Customer Account Totals

Vancouver Island								
Customer Class	Customer Accounts	2009	2010	2011	2012	2013	2014	2015
<b>Residential (Rate 1)</b>	Actual YE Customer Account Totals	88,321	90,671	92,554	92,067	94,173	97,162	
	Forecast Customer Account Totals	88,394	90,106	92,811	95,460	98,023	95,858	99,921
	Variance (units)	73	(565)	257	3,393	3,850	(1,304)	
	Variance (%)	0%	-1%	0%	4%	4%	-1%	
<b>Commercial (Rate AGS, SCS1, SCS2, LCS1, LCS2, LCS3)</b>	Actual YE Customer Account Totals	9,383	9,465	9,548	9,021	9,204	9,386	
	Forecast Customer Account Totals	9,285	9,470	9,600	9,641	9,736	9,176	
	Variance (units)	(98)	5	52	620	532	(210)	
	Variance (%)	-1%	0%	1%	7%	6%	-2%	

4

5

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1 **Vancouver Island: Annual Customer Additions**

Vancouver Island		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Customer Additions</b>							
<b>Residential (Rate 1)</b>	Actual Annual Customer Additions	2,785	2,350	1,883	1,845	2,106	2,989	
	Forecast Customer Additions	2,694	2,200	2,705	2,462	2,563	2,001	2,759
	Variance (units)	(91)	(150)	822	617	457	(988)	
	Variance (%)	-3%	-6%	44%	33%	22%	-33%	
<b>Commercial (Rate AGS, SCS1, SCS2, LCS1, LCS2, LCS3)</b>	Actual Annual Customer Additions	149	82	83	176	185	194	
	Forecast Customer Additions	106	120	130	95	95	76	
	Variance (units)	(43)	38	47	(81)	(90)	(118)	
	Variance (%)	-29%	46%	57%	-46%	-49%	-61%	

3 **Vancouver Island: Average Normalized Use Per Customer**

Vancouver Island		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Average Normalized Use per Customer (GJ/yr)</b>							
<b>Residential (Rate 1)</b>	Actual Average Normalized UPC	56	50	56	50	49		
	Forecast Average Normalized UPC	58	54	54	48	46	45	43
	Variance (units)	2	4	(2)	(2)	(3)		
	Variance (%)	4%	8%	-3%	-4%	-6%		
<b>Commercial (Rate AGS, SCS1, SCS2, LCS1, LCS2, LCS3)</b>	Actual Average Normalized UPC	788	734	776	764	736		
	Forecast Average Normalized UPC	778	741	746	729	735	709	
	Variance (units)	(11)	8	(29)	(36)	(0)		
	Variance (%)	-1%	1%	-4%	-5%	0%		

5 **Vancouver Island: Total Normalized Energy Demand**

Vancouver Island		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Sales Volumes (TJ)</b>							
<b>Residential (Rate 1)</b>	Actual Total Normalized Energy Demand	4,913	4,548	5,143	4,596	4,606		
	Forecast Total Normalized Energy Demand	5,098	4,892	5,015	4,576	4,528	4,306	4,258
	Variance (units)	185	344	(127)	(20)	(78)		
	Variance (%)	4%	8%	-2%	0%	-2%		
<b>Commercial (Rate AGS, SCS1, SCS2, LCS1, LCS2, LCS3)</b>	Actual Total Normalized Energy Demand	7,397	6,944	7,405	6,893	6,771		
	Forecast Total Normalized Energy Demand	7,220	7,019	7,164	7,024	7,159	6,508	
	Variance (units)	(177)	75	(241)	131	388		
	Variance (%)	-2%	1%	-3%	2%	6%		

7 **Whistler: Year-End Customer Account Totals**

Whistler		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Accounts</b>							
<b>Residential (Rate 1)</b>	Actual YE Customer Account Totals	2,250	2,262	2,296	2,271	2,348	2,416	
	Forecast Customer Account totals	2,178	2,272	2,321	2,289	2,303	2,372	2,478
	Variance (units)	(72)	10	25	18	(45)	(44)	
	Variance (%)	-3%	0%	1%	1%	-2%	-2%	
<b>Commercial (Rate SGS1, LGS1, LGS2, LGS3)</b>	Actual YE Customer Account Totals	330	330	353	341	347	352	
	Forecast Customer Account totals	331	329	335	340	345	358	
	Variance (units)	1	(1)	(18)	(1)	(2)	6	
	Variance (%)	0%	0%	-5%	0%	-1%	2%	

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### Whistler: Annual Customer Additions

Whistler		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Customer Additions</b>							
<b>Residential (Rate 1)</b>	Actual Annual Customer Additions	116	12	34	51	77	68	
	Forecast Customer Additions	50	35	36	14	14	52	62
	Variance (units)	(66)	23	2	(37)	(63)	(16)	
	Variance (%)	-57%	192%	6%	-73%	-82%	-24%	
<b>Commercial (Rate SGS1, LGS1, LGS2, LGS3)</b>	Actual Annual Customer Additions	7	-	23	-	6	5	
	Forecast Customer Additions	13	1	3	5	5	9	
	Variance (units)	6	1	(20)	5	(1)	4	
	Variance (%)	86% n/a		-87% n/a		-17%	80%	

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### Whistler: Average Normalized Use Per Customer

Whistler		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Average Normalized Use per Customer (GJ/yr)</b>							
<b>Residential (Rate 1)</b>	Actual Average Normalized UPC	80	99	94	91	85		
	Forecast Average Normalized UPC	89	91	82	104	106	89	77
	Variance (units)	8.9	(7.8)	(12.1)	12.1	20.4		
	Variance (%)	0.1	(0.1)	(0.1)	0.1	0.2		
<b>Commercial (Rate SGS1, LGS1, LGS2, LGS3)</b>	Actual Average Normalized UPC	1,370	1,640	1,433	1,403	1,435		
	Forecast Average Normalized UPC	1,675	1,677	1,461	1,410	1,348	1,220	
	Variance (units)	304.3	36.5	28.0	6.9	(86.3)		
	Variance (%)	0.2	0.0	0.0	0.0	(0.1)		

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### Whistler: Total Normalized Energy Demand.

Whistler		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Energy (TJ)</b>							
<b>Residential (Rate 1)</b>	Actual Total Normalized Energy Demand	180	224	215	208	201		
	Forecast Total Normalized Energy Demand	193	207	189	237	244	211	191
	Variance (units)	14	(17)	(26)	29	43		
	Variance (%)	8%	-7%	-12%	14%	22%		
<b>Commercial (Rate SGS1, LGS1, LGS2, LGS3)</b>	Actual Total Normalized Energy Demand	452	541	506	479	498		
	Forecast Total Normalized Energy Demand	554	552	489	480	465	437	
	Variance (units)	102	10	(16)	1	(33)		
	Variance (%)	23%	2%	-3%	0%	-7%		

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5.1.1 Please produce a final set of four tables which will consolidate the service area data into FEI totals. Please use the headings provided above and provide the consolidated tables in a functional excel spreadsheet as well as on paper.

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1 **Response:**

2 Please see consolidated tables below which have been prepared by summing the information  
 3 for the years 2009 to 2014 from the response to BCUC IR 1.5.1 using the rate schedule  
 4 groupings indicated in the first column. This is not the same mapping as was determined for  
 5 2015 and therefore the years prior to 2015 are not comparable with 2015. Please refer to  
 6 Attachment 5.1.1 for the fully functioning Excel file.

7 **Consolidated Accounts**

Consolidated		2009	2010	2011	2012	2013	2014	2015
<b>Customer Class</b>	<b>Accounts</b>							
<b>Residential (RS 1)</b>	Actual YE Customer Account Totals	844,306	853,492	860,403	854,050	863,189	873,661	
	Forecast Customer Account totals	846,375	849,539	860,742	870,980	880,331	866,852	883,371
	Variance (units)	2,069	(3,953)	339	16,930	17,142	(6,809)	
	Variance (%)	0%	0%	0%	2%	2%	-1%	
<b>Commercial (RS 2,3 AGS, SCS1, SCS2, LCS1, LCS2, LCS3,SGS1, LGS1)</b>	Actual YE Customer Account Totals	90,540	90,705	91,201	86,272	87,629	88,827	
	Forecast Customer Account totals	90,016	92,086	92,298	91,069	91,258	87,033	89,768
	Variance (units)	(524)	1,381	1,097	4,797	3,629	(1,794)	
	Variance (%)	-1%	2%	1%	6%	4%	-2%	
<b>Small Industrial/Seasonal (RS 4,5,7 &amp; 16)</b>	Actual YE Customer Account Totals	288	244	231	233	227	224	
	Forecast Customer Account totals	287	290	271	247	247	230	224
	Variance (units)	(1)	46	40	14	20	6	
	Variance (%)	0%	19%	17%	6%	9%	3%	
<b>Commercial (RS 23)</b>	Actual YE Customer Account Totals	1,348	1,406	1,433	1,520	1,529	1,522	
	Forecast Customer Account totals	1,426	1,319	1,366	1,526	1,586	1,634	1,552
	Variance (units)	78	(87)	(67)	6	57	112	
	Variance (%)	6%	-6%	-5%	0%	4%	7%	
<b>Small Industrial (RS 25 &amp; 27)</b>	Actual YE Customer Account Totals	703	658	608	606	593	641	
	Forecast Customer Account totals	686	678	657	658	658	588	641
	Variance (units)	(17)	20	49	52	65	(53)	
	Variance (%)	-2%	3%	8%	9%	11%	-8%	
<b>Large Industrial (RS 22, 22A &amp; 22B)</b>	Actual YE Customer Account Totals	45	43	43	46	45	46	
	Forecast Customer Account totals	47	45	45	43	43	45	46
	Variance (units)	2	2	2	(3)	(2)	(1)	
	Variance (%)	4%	5%	5%	-7%	-4%	-2%	
<b>NGV (RS 6)</b>	Actual YE Customer Account Totals	29	24	20	16	12	15	
	Forecast Customer Account totals	32	32	32	21	21	14	15
	Variance (units)	3	8	12	5	9	(1)	
	Variance (%)	10%	33%	60%	31%	75%	-7%	

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### Consolidated Accounts Additions

Consolidated								
Customer Class	Customer Additions	2009	2010	2011	2012	2013	2014	2015
<b>Residential (RS 1)</b>	Actual Annual Customer Additions	7,723	9,186	6,911	6,371	9,139	10,472	
	Forecast Customer Additions	9,154	7,364	8,762	8,983	9,351	6,647	9,710
	Variance (units)	1,431	(1,822)	1,851	2,612	212	(3,825)	
	Variance (%)	19%	-20%	27%	41%	2%	-37%	
<b>Commercial (RS 2,3 AGS, SCS1, SCS2, LCS1, LCS2)</b>	Actual Annual Customer Additions	413	165	496	357	1,359	1,210	
	Forecast Customer Additions	606	935	923	189	189	416	974
	Variance (units)	193	770	427	(168)	(1,170)	(794)	
	Variance (%)	47%	467%	86%	-47%	-86%	-66%	
<b>Small Industrial/ Seasonal (RS 4,5,7 &amp; 16)</b>	Actual Annual Customer Additions	(19)	(44)	(13)	4	(6)	(3)	
	Forecast Customer Additions	-	-	-	-	-	-	0
	Variance (units)	19	44	13	(4)	6	3	
	Variance (%)	n/a	n/a	n/a	n/a	n/a	n/a	
<b>Commercial (RS 23)</b>	Actual Annual Customer Additions	42	58	27	88	9	(7)	
	Forecast Customer Additions	53	9	9	60	60	57	30
	Variance (units)	11	(49)	(18)	(28)	51	64	
	Variance (%)	26%	-84%	-67%	-32%	567%	-914%	
<b>Small Industrial (RS 25 &amp; 27)</b>	Actual Annual Customer Additions	(2)	(45)	(50)	(1)	(13)	48	
	Forecast Customer Additions	1	-	-	-	-	-	0
	Variance (units)	3	45	50	1	13	(48)	
	Variance (%)	-150%	n/a	n/a	n/a	n/a	n/a	
<b>Large Industrial (RS 22, 22A &amp; 22B)</b>	Actual Annual Customer Additions	(7)	(2)	-	3	(1)	1	
	Forecast Customer Additions	(1)	-	-	-	-	-	0
	Variance (units)	6	2	-	(3)	1	(1)	
	Variance (%)	-86%	n/a	n/a	n/a	n/a	n/a	
<b>NGV (RS 6)</b>	Actual Annual Customer Additions	(3)	(5)	(4)	(3)	(4)	3	
	Forecast Customer Additions	-	-	-	-	-	-	0
	Variance (units)	3	5	4	3	4	(3)	
	Variance (%)	n/a	n/a	n/a	n/a	n/a	n/a	

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### Consolidated UPC

Consolidated								
Customer Class	Average Normalized Use per Customer (GJ/yr)	2009	2010	2011	2012	2013	2014	2015
<b>Residential (RS 1)</b>	Actual Average Normalized UPC	88.9	87.7	86.3	87.3	84.4		
	Forecast Average Normalized UPC	87.2	87.4	85.7	85.8	84.7	85.4	81.1
	Variance (units)	8.9	(7.8)	(12.1)	12.1	20.4		
	Variance (%)	11.1%	-7.9%	-12.9%	13.3%	23.9%		
<b>Commercial (RS 2,3 AGS, SCS1, SCS2, LCS1, LCS2, LCS3, SGS1, LGS1)</b>	Actual Average Normalized UPC	536	524	534	561	542		
	Forecast Average Normalized UPC	496	530	535	521	520	557	527
	Variance (units)	(40.3)	5.9	1.8	(40.8)	(21.6)		
	Variance (%)	(0.1)	0.0	0.0	(0.1)	(0.0)		
<b>Small Industrial/Seasonal (RS 4,5,7 &amp; 16)</b>	Actual Average Normalized UPC	10,776	9,925	11,124	11,105	11,361		
	Forecast Average Normalized UPC	10,072	11,344	11,345	10,076	10,089	10,374	10,634
	Variance (units)	(704)	1,419	221	(1,029)	(1,272)		
	Variance (%)	-7%	14%	2%	-9%	-11%		
<b>Commercial (RS 23)</b>	Actual Average Normalized UPC	4,882	4,861	5,127	5,248	5,142		
	Forecast Average Normalized UPC	4,424	4,686	4,687	4,949	4,974	5,546	5,309
	Variance (units)	(459)	(175)	(441)	(299)	(168)		
	Variance (%)	-9%	-4%	-9%	-6%	-3%		
<b>Small Industrial (RS 25 &amp; 27)</b>	Actual Average Normalized UPC	27,357	27,762	30,327	30,238	31,843		
	Forecast Average Normalized UPC	25,695	28,621	28,621	29,199	29,295	30,831	29,971
	Variance (units)	(1,662)	859	(1,706)	(1,039)	(2,548)		
	Variance (%)	-6%	3%	-6%	-3%	-8%		
<b>Small Industrial - Total (RS 23, 25, 27, 4, 5, 7, &amp; 16)</b>	Actual Average Normalized UPC	12,342	12,156	12,806	12,557	12,764		
	Forecast Average Normalized UPC	11,313	12,656	12,625	12,267	12,129	12,380	12,317
	Variance (units)	(1,030)	499	(181)	(290)	(636)		
	Variance (%)	-8%	4%	-1%	-2%	-5%		
<b>NGV (RS 6)</b>	Actual Average Normalized UPC	3,074	2,440	3,450	3,647	3,571		
	Forecast Average Normalized UPC	3,125	3,244	3,250	2,686	2,686	3,663	3,179
	Variance (units)	51	804	(200)	(961)	(886)		
	Variance (%)	2%	33%	-6%	-26%	-25%		

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### Consolidated Energy Demand

Consolidated								
Customer Class	Energy (TJ)	2009	2010	2011	2012	2013	2014	2015
<b>Residential (RS 1)</b>	Actual Total Normalized Energy Demand	75,092	74,813	74,291	74,557	72,895		
	Forecast Total Normalized Energy Demand	73,788	74,273	73,784	74,703	74,588	74,029	71,656
	Variance (units)	(1,303)	(540)	(507)	146	1,692		
	Variance (%)	-2%	-1%	-1%	0%	2%		
<b>Commercial (RS 2,3 AGS, SCS1, SCS2, LCS1, LCS2, LCS3,SGS1, LGS1,)</b>	Actual Total Normalized Energy Demand	48,565	47,498	48,672	48,434	47,476		
	Forecast Total Normalized Energy Demand	44,660	48,764	49,425	47,412	47,471	48,445	47,318
	Variance (units)	(3,905)	1,266	753	(1,023)	(4)		
	Variance (%)	-8%	3%	2%	-2%	0%		
<b>Small Industrial/ Seasonal (RS 4,5,7 &amp; 16)</b>	Actual Total Normalized Energy Demand	3,168	2,660	2,870	2,743	2,738		
	Forecast Total Normalized Energy Demand	3,092	3,392	3,392	2,604	2,607	2,482	2,480
	Variance (units)	(76)	732	522	(139)	(131)		
	Variance (%)	-2%	28%	18%	-5%	-5%		
<b>NGV (RS 6)</b>	Actual Total Normalized Energy Demand	83	61	69	62	50		
	Forecast Total Normalized Energy Demand	100	104	104	56	56	51	48
	Variance (units)	17	43	35	(6)	6		
	Variance (%)	20%	70%	51%	-10%	12%		
<b>Customer Class</b>	<b>Transportation Volumes (TJ)</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>	<b>2015</b>
<b>Commercial (RS 23)</b>	Actual Total Normalized Energy Demand	6,469	6,630	7,373	7,803	7,867		
	Forecast Total Normalized Energy Demand	6,109	6,134	6,177	7,151	7,485	8,721	8,255
	Variance (units)	(360)	(496)	(1,196)	(652)	(382)		
	Variance (%)	-6%	-7%	-16%	-8%	-5%		
<b>Small Industrial (RS 25 &amp; 27)</b>	Actual Total Normalized Energy Demand	18,849	18,767	19,864	19,201	20,029		
	Forecast Total Normalized Energy Demand	17,678	19,405	19,405	19,213	19,276	18,684	19,211
	Variance (units)	(1,171)	638	(459)	12	(753)		
	Variance (%)	-6%	3%	-2%	0%	-4%		
<b>Large Industrial (RS 22, 22A &amp; 22B)</b>	Actual Total Normalized Energy Demand	26,324	30,050	34,943	38,037	36,401		
	Forecast Total Normalized Energy Demand	27,725	27,117	27,117	29,675	29,620	35,118	33,340
	Variance (units)	1,401	(2,933)	(7,826)	(8,362)	(6,781)		
	Variance (%)	5%	-10%	-22%	-22%	-19%		

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1   **6.0   Reference:   DEMAND FORECAST AND REVENUE AT EXISTING RATES**

2                           **Exhibit B-1: Section 3.3, p. 15**

3                           **Residential and Commercial use per customer forecast**

4           FEI's application states: "Individual UPC [use per customer] projections for each  
5           residential and commercial rate class are developed for each rate class by considering  
6           the recent (three-year) historical weather-normalized UPC."<sup>5</sup>

7           6.1   Were the Use per Customer (UPC) projections for each rate class initially  
8           developed by service region (Lower Mainland, Inland, Columbia, Vancouver  
9           Island, and Whistler) and then consolidated for Section 3.3 in the Application? If  
10          not, please explain why not.

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12   **Response:**

13   Confirmed.

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17          6.2   Please provide calculations, with explanations, showing how the 2015 UPC  
18          forecast was developed for each residential and commercial rate class. Include in  
19          your calculations and explanations how the recent three years of data was  
20          incorporated into the development of the forecasts and factors that were  
21          considered. If regional or service area UPC forecasts were developed, please  
22          include them in your calculations and explanations.

23  
24   **Response:**

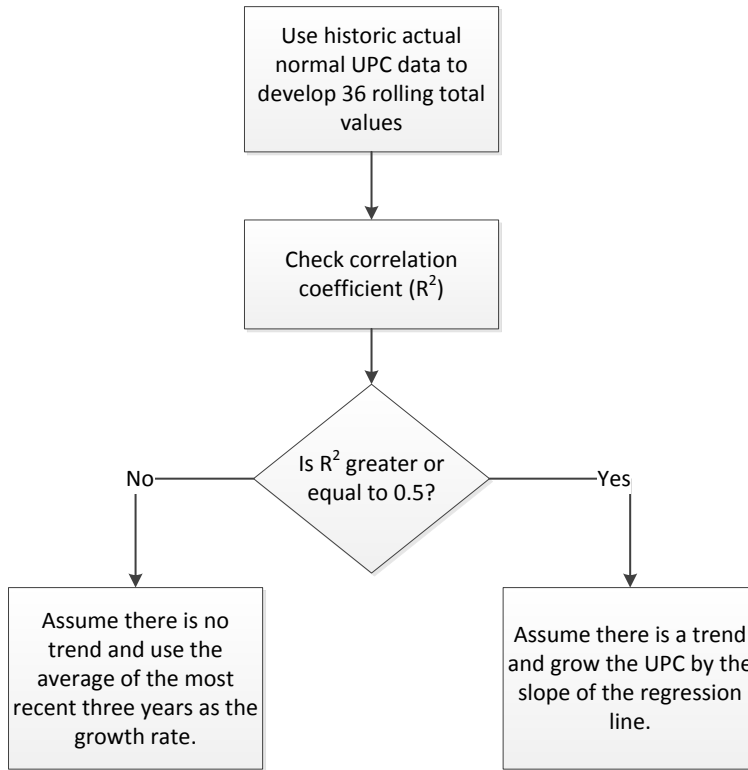
25   A regional UPC forecast is developed for Rate Schedules 1, 2, 3 and 23.

26   The UPC method is either a three-year average or the result of a regression. The regression is  
27   used only if a trend is present ( $R^2$  value greater than or equal to 50 percent). The following flow  
28   chart demonstrates the process.

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<sup>5</sup> Exhibit B-1, p. 15.

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3 To demonstrate the method, two rate classes are shown as examples below. All regions and  
 4 rate classes can be found in the Excel files provided in Attachment 6.2.

5 **Inland Rate Schedule 2**

6 The rolling 12-month UPCs are calculated as follows:



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Date	Monthly UPC	12 month Rolling UPC	Period
Jan-10	52.3		
Feb-10	41.2		
Mar-10	33.3		
Apr-10	19.8		
May-10	10.9		
Jun-10	7.1		
Jul-10	6.9		
Aug-10	6.4		
Sep-10	8.7		
Oct-10	20.0		
Nov-10	31.5		
Dec-10	48.9	287.0	
Jan-11	51.1	285.7	1
Feb-11	40.9	285.4	2
Mar-11	37.4	289.5	3
Apr-11	17.9	287.6	4
May-11	10.5	287.1	5
Jun-11	5.4	285.4	6
Jul-11	5.1	283.6	7
Aug-11	6.3	283.5	8
Sep-11	9.8	284.5	9
Oct-11	20.0	284.5	10
Nov-11	31.8	284.8	11
Dec-11	48.1	284.0	12
Jan-12	51.7	284.6	13
Feb-12	42.0	285.8	14
Mar-12	31.7	280.1	15
Apr-12	19.8	282.0	16
May-12	10.6	282.1	17
Jun-12	7.2	283.9	18
Jul-12	6.4	285.2	19
Aug-12	6.8	285.8	20
Sep-12	8.8	284.8	21
Oct-12	20.5	285.3	22
Nov-12	36.6	290.2	23
Dec-12	51.8	293.9	24
Jan-13	50.7	292.9	25
Feb-13	39.2	290.1	26
Mar-13	28.8	287.1	27
Apr-13	17.7	285.0	28
May-13	10.2	284.6	29
Jun-13	7.2	284.6	30
Jul-13	6.4	284.6	31
Aug-13	7.0	284.8	32
Sep-13	9.5	285.5	33
Oct-13	21.5	286.5	34
Nov-13	35.5	285.3	35
Dec-13	50.2	283.7	36



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1  
2 The following summary is developed:

	2010	2011	2012	2013	2014F	2015F
UPC	287.0	284.0	293.9	283.7	282.7	281.8
Growth		-1.0%	3.5%	-3.5%		
3 Yr avg	-0.34%					
Correlation	1%					
Result	Use 3 Yr Avg					

3  
4  
5 The correlation coefficient is 1 percent, so a three-year average is used, as per the flow chart  
6 above.

7 The three year average UPC growth rate is -0.34 percent.

8 The 2013 normalized actual value of 283.7 is grown at (1-0.34) and results in the 2014F UPC of  
9 282.7. The 2014F value is once again grown at (1-0.34) to establish the 2015F value of 281.8.

10 **Lower Mainland Rate Schedule 23**

11 Lower Mainland Rate Schedule 23 is an example of a rate class where the 36 monthly rolling  
12 totals show a statistically significant trend.



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Date	Monthly UPC	12 month Rolling UPC	Period
Jan-10	656.1		
Feb-10	557.2		
Mar-10	534.3		
Apr-10	410.3		
May-10	276.5		
Jun-10	195.6		
Jul-10	144.0		
Aug-10	103.1		
Sep-10	275.0		
Oct-10	371.9		
Nov-10	553.8		
Dec-10	695.3	4,773	
Jan-11	690.4	4,807	1
Feb-11	556.3	4,807	2
Mar-11	636.4	4,909	3
Apr-11	438.1	4,937	4
May-11	316.4	4,976	5
Jun-11	210.1	4,991	6
Jul-11	168.8	5,016	7
Aug-11	181.4	5,094	8
Sep-11	240.7	5,060	9
Oct-11	401.9	5,090	10
Nov-11	529.5	5,065	11
Dec-11	648.9	5,019	12
Jan-12	694.2	5,023	13
Feb-12	608.8	5,075	14
Mar-12	575.0	5,014	15
Apr-12	451.3	5,027	16
May-12	310.5	5,021	17
Jun-12	223.9	5,035	18
Jul-12	166.9	5,033	19
Aug-12	180.4	5,032	20
Sep-12	216.8	5,008	21
Oct-12	414.8	5,021	22
Nov-12	607.9	5,099	23
Dec-12	659.2	5,110	24
Jan-13	684.8	5,100	25
Feb-13	614.1	5,106	26
Mar-13	588.2	5,119	27
Apr-13	458.9	5,126	28
May-13	323.3	5,139	29
Jun-13	247.5	5,163	30
Jul-13	166.0	5,162	31
Aug-13	174.7	5,156	32
Sep-13	239.4	5,179	33
Oct-13	382.9	5,147	34
Nov-13	551.7	5,091	35
Dec-13	650.3	5,082	36



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1 The following summary is developed:

	2010	2011	2012	2013	2014F	<b>2015F</b>
UPC	4,773	5,019	5,110	5,082	5,161	5,241
Growth		5.1%	1.8%	-0.5%		
3 Yr avg	2.14%					
Correlation	63%					
Slope	6.62					
Result	Use Regression					

2

3

4 The correlation coefficient is 63 percent so the regression is used, as per the flow chart above.

5 The slope of the regression equation is 6.62.

6 The 2013 normalized actual value of 5,082 is grown at (12 X 6.62) and results in the 2014F  
7 UPC of 5,161. The 2014F value is once again grown at (12 X 6.61) to establish the 2015F value  
8 of 5,241.

9 Results for all other rate classes and regions are shown in the Excel spreadsheets provided in  
10 Attachment 6.2.

11



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1 **7.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES**

2 **Exhibit B-1: Section 3.4, pp. 18-20; Appendix A3**

3 **Residential net customer additions forecast**

4 FEI's application states: "The Conference Board of Canada (CBOC) housing starts  
5 forecast found in Appendix A3 provides a proxy for residential net customer additions..."<sup>6</sup>

6 7.1 Please state the city/region/province for which the CBOC housing starts forecast  
7 found in Appendix A3 was created.

8  
9 **Response:**

10 The CBOC prepares their forecasts at the provincial level. The forecast in Appendix A3 was for  
11 the province of BC. The forecast was from the CBOC forecast of November 24, 2014, Provincial  
12 Medium Term, Forecast 15 Run: 15 Table LTPF 156 and LTPF 157.

13  
14

15  
16 7.2 Figure 3-6 on page 20 of the Application shows a trend of increasing residential  
17 net customer additions from 2012 through 2014. Please explain why FEI has  
18 forecasted a decrease in the number of residential net customer additions from  
19 the 2014 amount.

20  
21 **Response:**

22 The residential net customer additions forecast methodology relies on the CBOC forecast of  
23 housing starts and FEI's previous year net additions. This econometric forecasting technique is  
24 used for residential net customer additions since FEI has found a statistically significant  
25 correlation between the CBOC housing starts forecast and Rate Schedule 1 net customer  
26 additions. The forecast methodology does not consider 2012 or 2013 data.

27 Since the CBOC forecast for 2015 is declining, the forecast of net additions is also declining.  
28 For the complete calculation, refer to the response to BCUC IR 1.7.4.

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<sup>6</sup> Exhibit B-1, p. 19.



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7.3 Please complete the table below for each service region, using CBOC data where applicable, in a functional excel spreadsheet for each year from 2008 to 2014. Please include a hard copy response as well.

	Column 1	Column 2	Column 3	...	
		2008	2009	...	2014
Line 1	Forecasted Single-Detached Housing Starts (units)				
Line 2	Forecasted Percentage Change				
Line 3	Forecasted Multi-Family Housing Starts (Units)				
Line 4	Forecasted Percentage Change				
Line 5	Forecasted Housing Starts Total				
Line 6	Forecasted (RS 1) Net Customer Additions				
Line 7	Actual Residential (RS 1) Net Customer Additions				

- 6
- 7
- 8 **Response:**

9 A hard copy of the requested table is provided below. The BC Data is from the CBOC.



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<b>BC</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted Single-Detached Housing Starts (Units)	10,991.00	7,892.00	11,402.16	9,327.53	11,167.58	11,606.80	12,155.47
Forecasted Percentage Change	-24.1	-28.2	44.5	-18.2	19.7	3.9	4.7
Forecasted Multi-Family Housing Starts (Units)	23,330	8,185	14,889	15,799	18,836	19,963	20,953
Forecasted Percentage Change	-5.6	-64.9	81.9	6.1	19.2	6.0	5.0
<b>Forecasted Housing Starts Total</b>	<b>34,321.00</b>	<b>16,077.01</b>	<b>26,291.09</b>	<b>25,126.78</b>	<b>30,003.28</b>	<b>31,569.32</b>	<b>33,108.03</b>
<b>LML</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	7,457	3,604	2,909	3,566	4,617	4,813	2,471
Actual Residential (RS 1) Net Customer additions	4,636	3,183	4,574	3,356	2,413	4,271	4,641
<b>INL</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	3,459	2,666	2,048	2,245	1,683	1,754	2,008
Actual Residential (RS 1) Net Customer additions	3,040	1,479	2,028	1,545	1,959	2,447	2,593
<b>COL</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	170	130	160	197	207	207	115
Actual Residential (RS 1) Net Customer additions	267	160	222	100	111	224	168
<b>RSK</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	12	10	12	13	0	0	0
Actual Residential (RS 1) Net Customer additions	16	0	0	-7	-8	14	13
<b>Mainland</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	11,098	6,410	5,129	6,021	6,507	6,774	4,594
Actual Residential (RS 1) Net Customer additions	7,959	4,822	6,824	4,994	4,475	6,956	7,415
<b>Vancouver Island</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	3,479	2,694	2,200	2,705	2,462	2,563	2,001
Actual Residential (RS 1) Net Customer additions	3,326	2,785	2,350	1,883	1,845	2,106	2,989
<b>Whistler</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Forecasted (RS 1) Net Customer Additions	30	50	35	36	14	14	52
Actual Residential (RS 1) Net Customer additions	36	116	12	34	51	77	68

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Please refer to Attachment 7.3 for the fully functional Excel spreadsheet.

7.4 Please provide calculations, with accompanying explanations, which show how the residential net customer additions forecasts were developed. Please explain all the variables that were considered during the development of these forecasts and provide calculations and explanations which show how the CBOC housing starts were used in the forecasting process.

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1 **Response:**

2 The residential net customer additions forecast was developed based on the housing starts data  
 3 from the CBOC forecast of November 24, 2014, Provincial Medium Term, Forecast 15 Run: 15  
 4 Table LTPF 156 and LTPF 157, which is as follows:

**BC Housing Starts**

	2012	2013	2014	2015
<b>SFD</b>	8,333	8,296	9,080	8,216
<b>MFD</b>	19,132	18,511	19,176	20,062
	27,465	26,807	28,256	28,277

5

6 From the above housing starts data, the growth rates were calculated as follows:

**BC Housing Growth**

	2013	2014	2015
SFD	0%	9%	-10%
MFD	-3%	4%	5%

7

8 The following table shows the 2014 year ending actual accounts in column A. FEI proportions  
 9 the actual account additions into single family dwellings (SFD) and multi-family dwellings (MFD)  
 10 based on historical percentages from internal data. The percentages are shown in columns B  
 11 and C. The 2014 additions by SFD and MFD are then shown in columns D and E. Finally the  
 12 CBOC growth rates are applied to the MFD and SFD portions. This is shown in columns F and  
 13 G. The sum, by region, is shown in column H.

	2014A	% SFD	% MFD	2014A SFD	2014A MFD	2015F SFD	2015F MFD	2015F
	A	B	C	D	E	F	G	H
LML	4,641	80%	20%	3,713	928	3,359	971	4,331
INL	2,593	88%	12%	2,282	311	2,065	326	2,390
COL	168	85%	15%	143	25	129	26	156
RSV	13	100%		13	-	12	-	12
Vancouver Island	2,989	87%	13%	2,600	389	2,353	407	2,759
Whistler	68	100%	0%	68	-	62	-	62
<b>Total FEU</b>				8,819	1,653	7,980	1,730	9,709

14

15

16 Please refer to Attachment 7.4 for the analysis in Excel spreadsheet format.

17

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19



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1                    7.4.1    Please explain how: (i) market penetration rates; and (ii) time lag  
 2                                       between housing starts and new customers were incorporated into the  
 3                                       development of the residential net customer additions forecast.

4  
 5    **Response:**

6    Consistent with past practice, the FEI residential account forecast methodology does not rely on  
 7    market penetration rates. FEI uses the growth rates from the CBOC forecast as a proxy for the  
 8    growth rates of FEI net customer additions.

9    Time lag is not an issue in the account forecast methodology. Once the forecast of annual  
 10   additions has been developed, FEI assumes the pattern of actual monthly additions from the  
 11   prior year will be repeated in the forecast year.

12   For example in 2014 the actual additions were added to the system as follows:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	Additions	2,586	1,349	1,049	147	(400)	(428)	(457)	(185)	485	1,955	2,747	1,624	10,472

14   This is shown as a percentage of the annual additions as follows:

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	Additions	2,586	1,349	1,049	147	(400)	(428)	(457)	(185)	485	1,955	2,747	1,624	10,472
	Percent of Annual	24.7%	12.9%	10.0%	1.4%	-3.8%	-4.1%	-4.4%	-1.8%	4.6%	18.7%	26.2%	15.5%	

16   The 2015 forecast residential additions are 9,710. Using the same percentages as calculated for  
 17   2014 results in the 2015 monthly forecast, as follows:

2015	Total Additions	9710												
	Monthly Additions	2398	1251	973	136	-371	-397	-424	-172	450	1813	2547	1506	9,710

19

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1 **8.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES**

2 **Exhibit B-1, Section 3.4, pp. 18-21**

3 **Commercial net customer additions forecast**

4 FEI's application states: "...the commercial net customer additions forecast is based on  
 5 the average of the actual net customer additions over the last three years for which a full  
 6 year of actual data is available (i.e., 2012 to 2014)."<sup>7</sup>

7 Figure 3-7 on page 21 shows commercial net customer additions for 2012, 2013 and  
 8 2014 to be 561, 1,252 and 1,201, respectively.<sup>8</sup>

9 8.1 Please explain the methodology used to forecast commercial net customer  
 10 additions while taking into consideration that the 2012 commercial net customer  
 11 additions was significantly lower than that of 2013 and 2014.

12 **Response:**

13 Consistent with past practice, a three-year historical average of additions is calculated for Rate  
 14 Schedules 2, 3 and 23 for each region. The results are summed to provide the annual forecast  
 15 of commercial net customer additions.  
 16

17 The 1,004 net commercial additions for 2015 is calculated from the prior three years actual  
 18 additions as follows:

$$1,004 = \frac{(561 + 1,252 + 1,201)}{3}$$

19 The table below provides a discussion of different forecast methods. For the reasons shown in  
 20 the table, the Three Year Average time series is the most appropriate forecast method to  
 21 forecast commercial additions. FEI believes it is important that methodologies remain consistent  
 22 from year to year, and particularly over a specific rate setting period such as the PBR term, to  
 23 eliminate the potential to change the methodology to achieve a particular result.

Forecast Method	Discussion	Applicability to Account Additions Forecasting
<b>End Use</b>	The End Use forecast method is based on enumeration of end uses.	Inapplicable to commercial account forecasting. The End Use method is applicable to use rate forecasting only.

<sup>7</sup> Exhibit B-1, p. 19.

<sup>8</sup> Exhibit B-1, p. 21.

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Forecast Method	Discussion	Applicability to Account Additions Forecasting
<b>Econometric</b>	<p>Econometric forecasts are based on the idea that the dependent variable (e.g. account additions) is related to causal variables such as housing starts, GDP, income or mortgage rates.</p> <p>An independent forecast is required of the causal variable. The independent forecast can be supplied by the CBOC, BC STATS or others.</p>	<p>Applicable only if there is a relationship to a causal factor. FEI has been unable to find a causal factor with a strong relationship to commercial additions in any service territory.</p>
<b>Three Year Average</b>	<p>A time series forecast uses recent history to predict the short term future. The major drawback for time series forecasting over longer periods is the lack of a causal relationship.</p> <p>The forecast is only as good as the volatility of the historical data allows. If the historical data is volatile then the forecast can be expected to have some variance.</p> <p>Time series forecasts are used by FEI for short term forecasting and always include three years of history. Three years is the appropriate amount of history to forecast one or two periods forward.</p>	<p>Applicable because accurate historical data is available and the forecast period is short term in nature.</p> <p>Volatility in the historical data is high, so variance in the forecast may be high but is unavoidable.</p>
<b>Regression</b>	<p>Mathematical technique for finding the straight line that best-fits the values of a linear function, plotted on a scatter graph as data points. If a 'best fit' line is found, it can be used as the basis for estimating the future values of the function by extending it while maintaining its slope.</p> <p>Regression models must be tested for goodness of fit and other indicators. Not all regression models produce usable results.</p>	<p>Inapplicable because the goodness of fit is poor. The volatility in the actual commercial additions data prevents the regression method from being used.</p>
<b>Informed Opinion</b>	<p>For FEI an informed opinion forecast example is the annual industrial survey. FEI assumes that customers are best able to forecast their future demand requirements.</p>	<p>Inapplicable to account forecasting. Informed Opinion forecasts are useful for estimating industrial load and are implemented in the annual industrial survey.</p>

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8.1.1 Would a methodology that calculates the last two years of data be more indicative of the 2015 additions, rather than the last three years? Please discuss.



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**Response:**

No, FEI does not believe that a methodology that calculates the last two years of data, rather than the last three years, would be more indicative of the 2015 additions.

Consistent with past practice FEI uses a three-year average methodology to forecast commercial net customer additions. As shown in Figure 3-7, commercial account additions fluctuate significantly year over year. A three-year average is a reasonable way to account for these fluctuations. It is preferable for the purposes of comparability and consistency over time to continue to apply the existing forecasting method rather than to arbitrarily change the method to achieve a particular result or to intentionally include or exclude certain historical data points.

Figure 3-7 is an aggregate of Rate Schedules 2, 3 and 23. Each rate class is forecast independently. Each of these three rate classes was tested for outliers and none were found. Excluding data from the forecast method without any evidence of outliers is not advisable as there is no objective reason to believe removing the data will improve the forecast.

8.2 Please list and discuss the methodology behind other forecasting techniques that might be used to forecast commercial net customer additions, including but not limited to: (i) exponential smoothing; (ii) a weighted moving average; or (iii) a causal methodology which seeks to determine an explanatory variable such as economic activity.

**Response:**

FEI does not use exponential smoothing or weighted moving averages for any component of the forecast and as such cannot comment on the validity, applicability or performance of those two methods on any part of the forecast. A causal methodology was discussed in the table provided in response to BCUC IR 1.8.1 under “Econometric”. The methods in use are consistent with past practice and past results have been reasonable. Any variances in demand during the PBR term will be captured in either the RSAM or the Flow-through Variance deferral account.

8.2.1 Please compare the advantages and disadvantages of each forecasting technique presented in response to the previous question with the



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1 method used to produce the commercial net customer additions  
2 forecast in this Application.

3  
4 **Response:**

5 Please refer to the response to BCUC IR 1.8.2.

6  
7

8  
9 8.2.1.1 Does FEI consider that any of the forecasting techniques  
10 presented in response to the previous question may improve  
11 the accuracy of the commercial net customer addition  
12 forecasts? Please discuss.

13  
14 **Response:**

15 Please refer to the response to BCUC IR 1.8.2.

16

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1   **9.0   Reference:   DEMAND FORECAST AND REVENUE AT EXISTING RATES**

2                           **Exhibit B-1, Section 3.5.2, pp. 24-25**

3                           **Industrial Demand**

4           On page 24 of the Application, FEI states:

5                   The demand for the majority of industrial customers is forecast using the  
6                   Industrial Survey. For the 2015 forecast, customers completed the survey quite  
7                   recently, in October 2014, which is expected to result in greater accuracy than  
8                   has occurred in the past ... the response rate achieved in 2014 was 90 percent  
9                   of industrial customers surveyed.<sup>9</sup>

10           On page 25 of the Application, FEI states:

11                   To forecast volumes for the customers that were not included in the Industrial  
12                   Survey, their 2015 consumption was estimated using 2013 actuals or, where  
13                   applicable, using contract demand<sup>10</sup>.”

14                   Footnote 10 reads: “Including Burrard Thermal, Vancouver Island Joint Venture,  
15                   and BC Hydro Island Cogeneration Project.”<sup>10</sup>

16           9.1   Please explain why the 2015 forecast is expected to be more accurate than  
17                   previous years.

18  
19   **Response:**

20   FEI expects that the 2015 forecast will be more accurate because the 2015 forecast is based on  
21   an industrial survey that is more current compared to the industrial surveys relied upon for 2012-  
22   2013 and 2014 forecasts. As described below, recent experience has shown that large  
23   variances in Rate Schedule 22 demand are the result of fuel switching by a few customers, and  
24   one customer in particular, in response to changing natural gas prices and other energy costs  
25   for these customers. These fuel switching activities are not possible for FEI or customers to  
26   predict accurately. However, using an industrial survey closer to the test period, which provides  
27   the opportunity for the industrial customer to reflect the most recent information on natural gas  
28   and other energy costs in its forecast, mitigates the risk of fuel switching occurring during the  
29   test period that was not incorporated in the forecast demand.

30   In the 2012-2013 RRA filing, the annual demand forecast was prepared in 2011 based on the  
31   industrial survey completed in 2010. In the interim between the time of the survey in 2010 and  
32   the 2012-2013 test period, significant changes in gas prices and energy costs had occurred

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<sup>9</sup> Exhibit B-1, p. 24.

<sup>10</sup> Exhibit B-1, p. 25.



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1 which resulted in rate switching by large volume customers, and one customer in particular, to  
2 take advantage of the lower energy costs afforded by natural gas. The customers that began  
3 using significantly more gas were using other fuels at the time of the survey. As a result,  
4 significant variances occurred and were attributable to a select few customers.

5 In FEI's PBR Application, the 2014 load forecast was based on the industrial survey completed  
6 in November 2012. In the November 2012 survey, the customer that was primarily responsible  
7 for the variance in 2012 and 2013 submitted a forecast for a much larger volume of gas based  
8 on recent actual consumption, which appeared reasonable. In 2013, however, market  
9 conditions changed once again and this customer switched fuels for a second time, this time  
10 reducing the Rate Schedule 22 demand. The additional volume forecast in accordance with  
11 Directive 89 on page 295 of the PBR Decision, in reaction to the variance that occurred over  
12 2012-2013, exacerbated the 2014 variance.

13 In contrast to the 2012-2013 and 2014 forecast, the survey relied upon for the 2015 forecast  
14 was completed just two months prior to the start of the test period in October of 2014. The  
15 survey is more current than the one used in the 2012-2013 filing and as a result FEI believes it  
16 will be more accurate as customer responses to the survey will be based on more current  
17 information, including more current information on natural gas and other energy costs that might  
18 lead to fuel switching.

19  
20

21  
22 9.2 Please discuss the historical accuracy of the industrial survey forecasting method  
23 by referring to the variances for each of the industrial rate classes from 2009 to  
24 2014, presented in response to the previous BCUC IR requesting historic  
25 forecasts and actual demands (BCUC IR 5.1).

26  
27 **Response:**

28 The following table showing the industrial demand that is forecast using the survey method is  
29 copied here from the response to BCUC IR 1.5.1 for convenience:



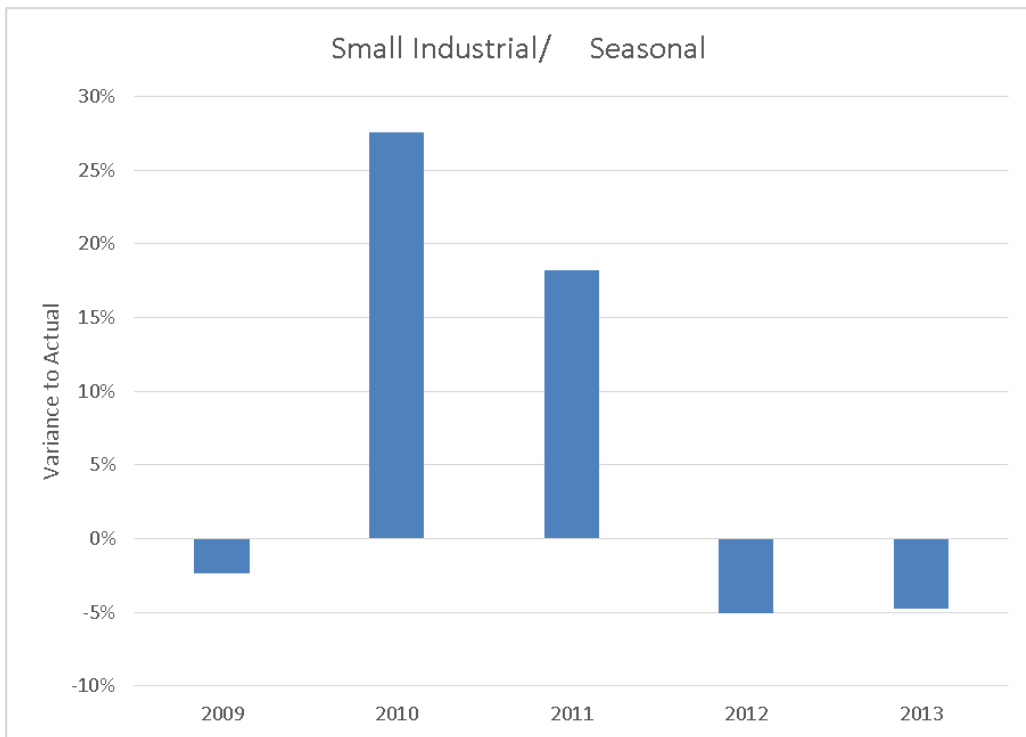
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Customer Class	Sales Volumes (TJ)	2009	2010	2011	2012	2013	2014	2015
<b>Small Industrial/ Seasonal (RS 4, 5, 7, &amp; 16/46)</b>	Actual Total Normalized Energy Demand	3,168	2,660	2,870	2,743	2,738		
	Forecast Total Normalized Energy Demand	3,092	3,392	3,392	2,604	2,607	2,482	2,480
	Variance (units)	(76)	732	522	(139)	(131)		
	Variance (%)	-2%	28%	18%	-5%	-5%		
<b>Small Industrial (RS 25 &amp; 27)</b>	Actual Total Normalized Energy Demand	18,849	18,767	19,864	19,201	20,029		
	Forecast Total Normalized Energy Demand	17,678	19,405	19,405	19,213	19,276	18,684	19,211
	Variance (units)	(1,171)	638	(459)	12	(753)		
	Variance (%)	-6%	3%	-2%	0%	-4%		
<b>Large Industrial (RS 22, 22A &amp; 22B)</b>	Actual Total Normalized Energy Demand	26,324	30,050	34,943	38,037	36,401		
	Forecast Total Normalized Energy Demand	27,725	27,117	27,117	29,675	29,620	35,118	33,340
	Variance (units)	1,401	(2,933)	(7,826)	(8,362)	(6,781)		
	Variance (%)	5%	-10%	-22%	-22%	-19%		

1  
 2 Variances are reported up to and including 2013. 2014 actual results will not be finalized until  
 3 the end of April 2015. As a result 2014 variances are not included or discussed.

4  
 5

**Small Industrial/Seasonal: Rate Schedule 4/5/7/16**



6  
 7  
 8 The aggregate variances in Rate Schedules 4/5/7/16 are both positive and negative indicating  
 9 that there is no bias. The average absolute variance is 12 percent. Many customers in this

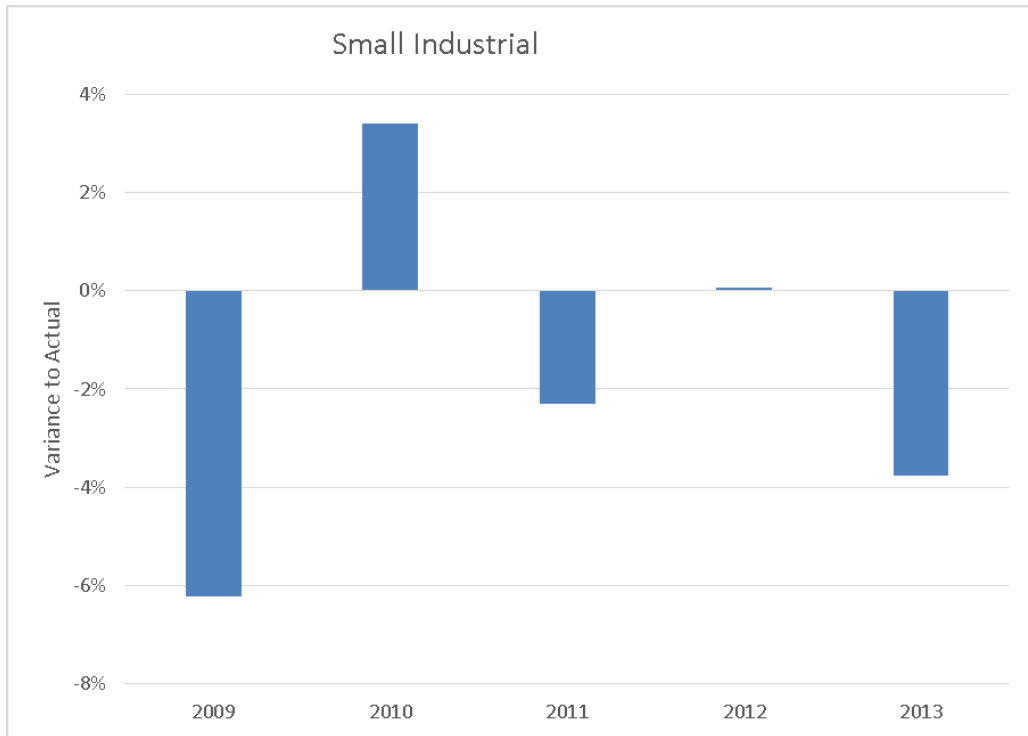


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1 group are heat sensitive and are therefore less able to predict their future demand. An example  
2 of this is 2010 where the actual consumption was significantly less than forecast due to the  
3 warmer than average temperatures. As a result the variance is higher because many customers  
4 assume “same as last year” for their forecast of consumption. This group accounts for 1.2  
5 percent of the total annual demand.

6

**Small Industrial: Rate Schedule 25/27**



7

8

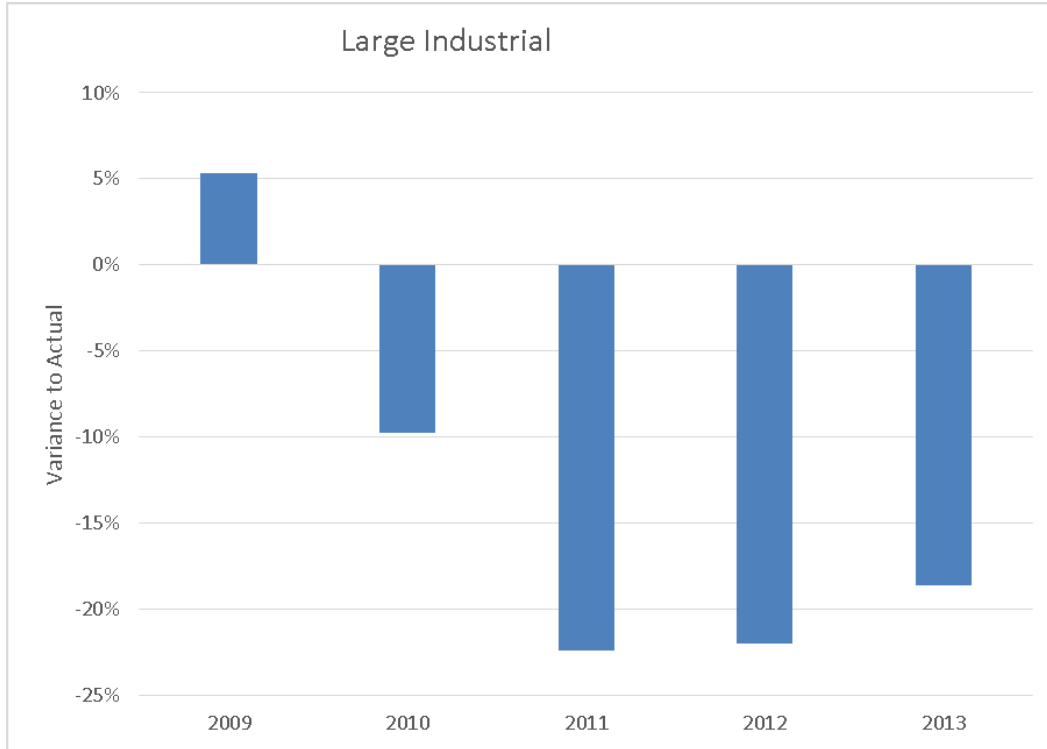
9 Variances for Rate Schedules 25/27 are small (maximum 6 percent) and both positive and  
10 negative indicating that there is no bias. The average absolute variance is 3 percent. Some  
11 customers in this group are heat sensitive and are therefore less able to predict their future  
12 demand. An example of this is 2010 where the actual consumption was less than forecast  
13 due to the warmer than average temperatures. This group accounts for more than 9 percent of the  
14 total annual demand.



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1

### Large Industrial: Rate Schedule 22



2

3

4 Variances for Rate Schedule 22 have averaged 16 percent over the period specified in the  
5 question. This group accounts for more than 16 percent of the total annual demand. Please  
6 refer to the response to BCUC IR 1.9.1 and 1.9.4 for a discussion of the recent history of  
7 variances for this Rate Schedule.

8

9

10

11 9.2.1 Please discuss the feasibility of using the historical accuracy of the  
12 industrial survey to determine the need for, and magnitude of, in-house  
13 adjustments to be made to survey forecasts in an effort to increase the  
14 accuracy of the industrial demand forecast.

15

16 **Response:**

17 The suggested mechanism is feasible, but due to the significant research and analysis required  
18 FEI cannot comment on any improvement or degradation in forecast performance that such a  
19 change might make. FEI will consider this, along with other alternatives, when it completes the



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1 research work to comply with Directive 90 regarding Rate Schedule 22 demand on page 194 of  
 2 the PBR Decision.

3  
 4

5

6 9.3 Please state the percentage of the actual 2013 demand that represents the total  
 7 demand of the 10 percent of the industrial customers that did not return a survey  
 8 response.

9

10 **Response:**

11 2.8 percent of the actual 2013 demand represents the total demand of the 10 percent of the  
 12 industrial customers that did not return a survey response.

13

14

15

16 9.4 Please explain factors that may have caused a decrease of 5.14 percent in  
 17 industrial energy demand in 2015 when compared to a reduction in demand by  
 18 0.6 percent in 2013 and 1.9 percent in 2014. Is there a specific sector or region  
 19 of industrial customers where the significant reduction in demand can be  
 20 attributed to?

21

22 **Response:**

23 In the course of responding to this IR, FEI has identified an error in the comparative historical  
 24 volumes (2005 through 2014) that were provided in Figure 3-8 and Figure 3-11. When the  
 25 historical volumes for FEI, FEVI, FEW were added together to produce these figures, the  
 26 intercompany volumes for Rate Schedule 22 Squamish and Whistler wheeling should have  
 27 been eliminated. After correcting for the removal of the wheeling volumes, the year-over-year  
 28 changes in the industrial demand are as follows:

	2012	2013	2014	2015
Industrial Volume	80.8	80.4	78.8	77.5
Year over year change		0.5%	2.0%	1.6%

29

30

31 As shown above, when corrected for the wheeling volumes, the year-over-year decline in  
 32 industrial volume for 2015 is now 1.6 percent and is no longer significant compared to prior  
 33 years. As discussed in response to CEC IR 1.22.1, since 2012, cement production facilities

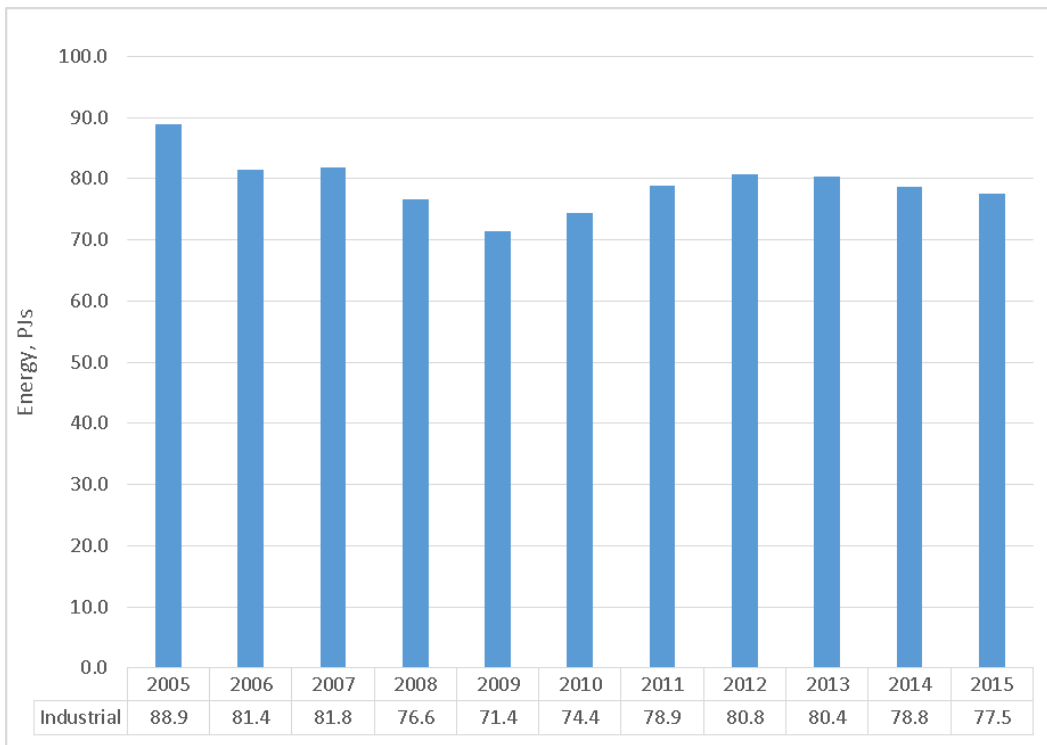
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1 have, over time, shifted the bulk of their requirements from natural gas to coal due to changes in  
 2 the differential in pricing between natural gas and coal. This fuel switching is the primary reason  
 3 behind the decline in Industrial demand since 2012.

4 Below are corrected Figures 3-11 and 3-8. This correction is a presentation issue only and  
 5 does not affect the financial schedules or revenue deficiency for 2015. FEI also notes that its  
 6 references throughout the Application (specifically on pages 6, 14, 21, and 28) should have  
 7 referenced a decrease in demand in 2015 of approximately 1 PJ rather than the approximately 4  
 8 PJs discussed.

9

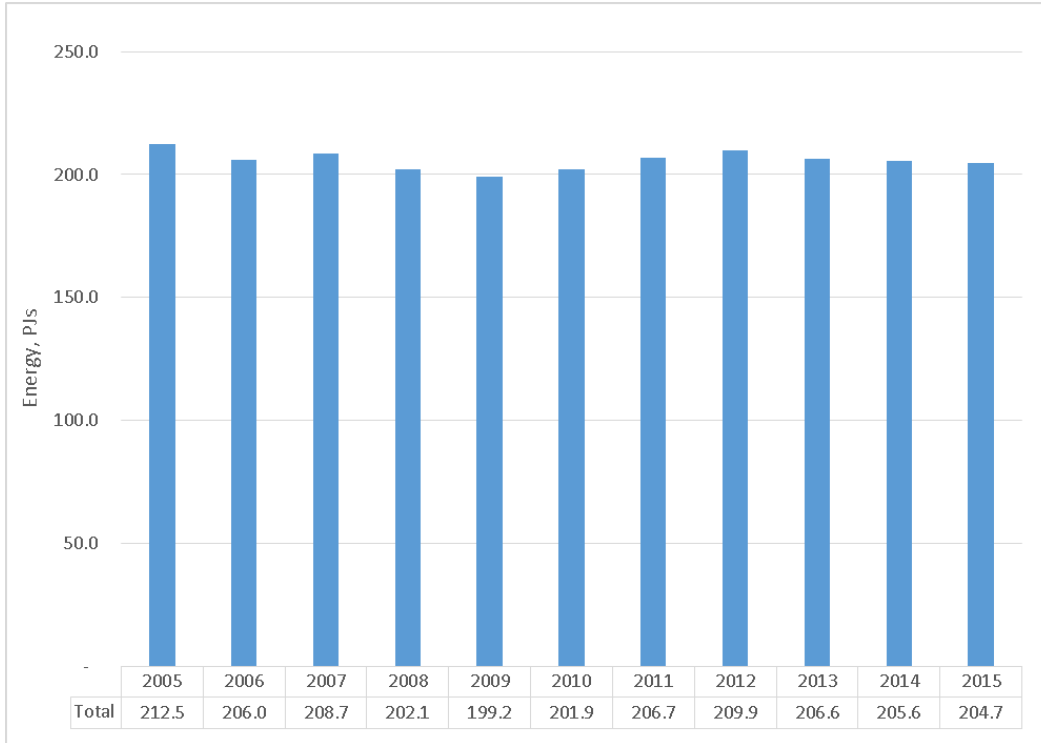
**Figure 3-11: Industrial Demand**



10

1

**Figure 3-8: Total Energy Demand in PJs**



2

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4

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7

9.5 Please provide the 2014 Actual and Approved Industrial Demand for each of FEI, FEVI and FEW.

8

9

10 **Response:**

11 Please see the table below for 2014 approved and 2014 projected industrial demand. Note that  
 12 2014 Actuals will not be available until end of April.

	2014 Approved Forecast	2014 Projection
Mainland	56.9	57.6
Vancouver Island	21.9	21.1
Whistler		0.1
<b>Total (PJs)</b>	<b>78.8</b>	<b>78.8</b>

13



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1 In the 2014 Approved Forecast there were no industrial customers forecast for Whistler. In  
2 anticipation of amalgamation, the 2014 Projections take into account customers moving into the  
3 common rates.

4  
5

6

7 9.6 Please separately indicate how much of the 2015 Forecast demand is related to  
8 FEI, FEVI and FEW customers.

9

10 **Response:**

11 The table below shows the 2015 Forecast Industrial demand related to each of Mainland,  
12 Vancouver Island and Whistler customers in PJs.

	2015 Forecast Demand (PJs)
Mainland	56.2
Vancouver Island	21.2
Whistler	0.1
<b>Total</b>	<b>77.5</b>

13

14

15

16

17 9.7 What impact, if any, does FEI believe that falling gas prices will have on industrial  
18 demand in 2015? Please discuss.

19

20 **Response:**

21 FEI cannot say definitively what impact falling gas prices will have on short term industrial  
22 demand for natural gas. If everything else were to remain the same, falling gas prices could be  
23 expected to result in increased industrial demand if gas prices dropped enough to cause fuel  
24 switching to natural gas for those industries that could do so, or if gas prices were low enough to  
25 induce increased industrial production in general. However, since there are many factors at  
26 play in whether an industry chooses to fuel switch or change production levels, including the  
27 price of competing fuels, the best way for FEI to forecast short term changes in industrial natural  
28 gas demand is to rely on the industrial demand survey.

29

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1   **10.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES**  
2                           **Exhibit B-1, Appendix D, p. 3; FEI 2014-2019 Multi-Year Performance**  
3                           **Based Ratemaking (PBR) Plan Decision, p. 194**  
4                           **Rate Schedule 22 Industrial Demand**

5           In the FEI PBR Decision, the Commission stated the following:

6                           Given the historical bias in the Rate Schedule 22 demand forecast, **the**  
7                           **Commission Panel does not approve the FEI’s 2014 Rate Schedule 22**  
8                           **demand forecast.** Moreover, FEI has not provided any recommendations to  
9                           improve the accuracy of Rate Schedule 22 demand forecast and Rate Schedule  
10                          22 has been under forecast by an average of 21 percent from 2008-2012.  
11                          **Therefore, the Commission Panel directs FEI to increase the 2014 Rate**  
12                          **Schedule 22 demand forecast by 21 percent.**

13                          **...The Commission Panel further directs FEI to develop a mechanism to**  
14                          **adjust the Rate Schedule 22 demand forecast methodology to better reflect**  
15                          **the impact of falling gas prices, for review at the 2015 Annual Review.<sup>11</sup>**

16           FEI states in Appendix D with regards to the Commission’s directive in the PBR  
17           Decision, as quoted above, that it will be “included in 2015 Annual Review for 2016  
18           Rates.”<sup>12</sup>

19           10.1 Does FEI consider that the Commission directive quoted in the above preamble  
20                           should have been carried out for the Annual Review for 2015 Rates proceeding?  
21                           If not, please explain why not.

22  
23   **Response:**

24   FEI did consider this. There were three reasons why FEI determined that it was the  
25   Commission’s intention for the directive to be undertaken as part of the “2015 Annual Review” to  
26   set 2016 rates.

- 27           1. The Commission used the words “in the first annual review” in three areas in the PBR  
28           Decision:
- 29                           a. the SQI Consultation process directive on page 155;
  - 30                           b. the description of annual review requirements on page 186; and
  - 31                           c. the discussion of non rate base deferral accounts on page 249.

<sup>11</sup> FortisBC Energy Inc. 2014-2019 Multi-Year Performance Based Ratemaking Plan Decision, p. 194.

<sup>12</sup> Exhibit B-1, Appendix D, p. 3.

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- 1 Had the Commission intended the Rate Schedule 22 directive to be completed before  
 2 the first annual review, it would have used language consistent with that used on the  
 3 three pages noted, namely “first annual review” rather than “2015 Annual Review”.
- 4 2. There was not sufficient time between the receipt of the PBR Decision and the filing for  
 5 2015 rates to allow for the work to be undertaken before the first annual review.
- 6 3. FEI contacted the Director, Rates at the Commission and confirmed verbally that the  
 7 proper interpretation was the 2015 Annual Review to set 2016 delivery rates.

8  
 9

- 10  
 11 10.2 Please indicate the percentage of (i) Industrial Demand; and (ii) Total Demand  
 12 that represents Rate Schedule 22 demand.

13  
 14 **Response:**

15 Rate Schedule 22 demand is 16 percent of total demand, or 43 percent of industrial demand.

16  
 17

- 18  
 19 10.3 Please provide the 2014 Approved and Actual, and the 2015 Forecast Industrial  
 20 Demand for Rate Schedule 22 in gigajoules and in dollars.

21  
 22 **Response:**

23 FEI’s 2014 actuals will not be finalized until April 30, 2015 when FEI’s annual report is submitted  
 24 to the Commission. The following table provides the 2014 approved, 2014 projected and the  
 25 2015 forecast Industrial Demand for Rate Schedule 22.

	<b>2014 Approved</b>	<b>2014 Projected</b>	<b>2015 Forecast</b>
<b>RS22<sup>1</sup> Demand</b>	43,245	35,118	33,340
<b>RS22<sup>2</sup> Revenue</b>	\$ 26,796	\$ 25,833	\$ 24,523

Note 1: Includes Rate 22, 22A, 22B Non-Bypass and Bypass demand in TJ’s

Note 2: Includes Rate 22, 22A, 22B Non-Bypass and Bypass revenue at existing rates (\$000)



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10.4 Please show with calculations how an increase of 21 percent to the Rate Schedule 22 forecast would impact the 2015 forecast for (i) Total Industrial Demand; (ii) FEI Total Normalized Energy Demand; and (iii) the forecasted 2015 revenue deficiency.

**Response:**

10 In increase in Rate Schedule 22 demand forecast of 21 percent would result in an increase to  
11 both Total Industrial Demand and FEI Total Normalized Energy Demand of 7,001.3 TJ and  
12 would reduce FEI's revenue deficiency by approximately \$3.037 million. FEI has included a  
13 table of calculations for reference.

14 Please refer to the response to BCUC IR 1.10.1 for the reasons why this adjustment to the 2015  
15 forecast is not reasonable.



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	Forecast Volume (TJ's) <sup>1</sup>	21% Increment	Variable Delivery Charge \$ / GJ	Gross Incremental Revenue \$000's
<u>Non-Bypass</u>				
Rate 22 - Large Transportation Service	11,790	2,475.9	0.957 <sup>2</sup>	\$ 2,369.48
Rate 22A - Large Transportation Service				
Firm Service	7,844	1,647.2	0.107 <sup>2</sup>	176.25
Interruptible Service	727	152.6	1.208 <sup>2</sup>	184.32
Rate 22B - Large Transportation Service				
Firm Service	2,760	579.6	0.105 <sup>2</sup>	60.86
Interruptible Service	19	3.9	1.162 <sup>3</sup>	4.54
<u>Bypass</u>				
Rate 22 - Large Transportation Service	7,260	1,524.6	0.116 <sup>4</sup>	176.85
Rate 22B - Large Transportation Service	<u>2,940</u>	<u>617.5</u>	<u>0.105</u> <sup>2</sup>	<u>64.83</u>
	33,340	7,001.3 <sup>(i) (ii)</sup>		\$ 3,037.13 <sup>(iii)</sup>

- Note 1: Section 11, Schedule 7, Lines 20 + 21 plus Schedule 8, Line 3 + 5
- Note 2: FEI's 2015 Common Delivery Rates and Delivery Rate Riders approved by BCUC Order G-178-14, Table 6, Lines 11, 12, 13, 14, 17
- Note 3: FEI's 2015 Common Delivery Rates and Delivery Rate Riders approved by BCUC Order G-178-14, Table 6, Line 18 x 7/12 + Line 19 x 5/12
- Note 4: Section 11, Schedule 8, Line 3 Column 3

1  
2

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1 **D. OTHER REVENUE**

2 **11.0 Reference: NGT RELATED RECOVERIES**

3 **Exhibit B-1: Section 5.2.4, p. 33; Appendix B, Table B-4, p. 7;**

4 **Exhibit A2-1, Evergreen Industries demand forecast**

5 FEI forecasts 2015 Evergreen Industries demand as 1,250 GJ.<sup>13</sup>

6 FEI states: Evergreen will consume 500 GJ per year for the one CNG waste hauler for  
7 the time being.<sup>14</sup>

8 11.1 Please explain the difference between 2015 Evergreen Industries demand  
9 forecast of 1,250 GJ in the Application and the 500 GJ/year forecast in the  
10 Evergreen CNG application.

11

12 **Response:**

13 The demand of 500 GJ referenced in the Evergreen CNG agreement, which was attached to the  
14 CNG rate approval application, was for the operation of 1 CNG waste hauler to be put in  
15 operation in January 2015. Evergreen is unsure of when their 2<sup>nd</sup> waste hauler will be in  
16 operation and therefore was only willing to execute a supply agreement for 500 GJ at that time.

17 Evergreen will add at least one CNG waste hauler to their fleet later in 2015, which is expected  
18 to bring their consumption close to 1,250 GJ per year as forecast in the Application, and their  
19 annual take-or-pay demand commitment will be increased at that time.

20 FEI notes that Evergreen contracted for 500 GJ to ensure that their take-or-pay commitment  
21 was sufficiently below the actual consumption for one waste hauler. Although Evergreen  
22 expects to consume more than 500 GJ per truck, contracting for a take-or-pay for 500 GJ  
23 protects the customer from committing to a higher quantity without fully knowing what actual  
24 consumption will be. Evergreen will have the ability to increase their take-or-pay commitment  
25 once actual consumption is known over the course of operation.

26

---

<sup>13</sup> Exhibit B-1, Appendix B, p. 7.

<sup>14</sup> Exhibit A2-1.

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1 **12.0 Reference: BIOMETHANE OTHER REVENUE**

2 **Exhibit B-1: Section 5.2.5, pp. 33-34**

3 **Biomethane other revenue**

4 FEI states: "The other revenue reduction of \$0.070 million in 2015 shown in Table 5-1  
 5 above is the transfer from the delivery margin to the Biomethane Variance Account  
 6 (BVA) of the cost of service of the Biomethane capital assets."<sup>15</sup>

7 12.1 Please provide the 2014 and 2015 Biomethane cost of service of the Biomethane  
 8 capital assets.  
 9

10 **Response:**

11 The Biomethane cost of service, including the components for the biomethane upgraders for the  
 12 Salmon Arm Landfill project and the Kelowna Landfill project, projected for 2014 and forecast for  
 13 2015 is provided in the table below. The debit of \$70 thousand charged to Other Revenue in  
 14 2015 is the sum of the Income Tax and Earned Return impacts from the mid-year net  
 15 investment in the upgrader plant.

16 **Biomethane Cost of Service (\$ Thousands)**

Particulars	2014				2015			
	Salmon Arm Landfill	Kelowna Landfill	General Costs	Total	Salmon Arm Landfill	Kelowna Landfill	General Costs	Total
O & M Expenditure	92	30	300	422	80	208	306	594
Property Taxes	2	-	3	5	2	2	9	13
Depreciation	<u>133</u>	<u>154</u>	<u>-</u>	<u>287</u>	<u>144</u>	<u>307</u>	<u>-</u>	<u>451</u>
Subtotal	<u>227</u>	<u>184</u>	<u>303</u>	<u>714</u>	<u>226</u>	<u>517</u>	<u>315</u>	<u>1,058</u>
Income Tax	(201)	(300)	-	(500)	(91)	(411)	-	(502)
Earned Return	<u>137</u>	<u>165</u>	<u>-</u>	<u>302</u>	<u>131</u>	<u>301</u>	<u>-</u>	<u>432</u>
Subtotal - Other Revenue	<u>(64)</u>	<u>(135)</u>	<u>-</u>	<u>(199)</u>	<u>40</u>	<u>(110)</u>	<u>-</u>	<u>(70)</u>
Total Cost of Service	<u>\$ 163</u>	<u>\$ 49</u>	<u>\$ 303</u>	<u>\$ 515</u>	<u>\$ 267</u>	<u>\$ 407</u>	<u>\$ 315</u>	<u>\$ 988</u>

17

18

<sup>15</sup> Exhibit B-1, p. 33.

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1 **13.0 Reference: LNG CAPACITY ASSIGNMENT**

2 **Exhibit B-1: Section 5.4, p. 36; Section 5.1, Table 5-1, p. 31**

3 FEI's states:

4 The \$18.039 million in LNG capacity assignment other revenue...represents a  
5 transfer of costs from the delivery margin to gas costs reflecting to the allocation  
6 of a portion the Mt. Hayes LNG facility to gas costs ... The 2015 transfer reflects  
7 the level of LNG service provided to the gas supply portfolio and is consistent  
8 with the level of service provided pre-amalgamation. Generally, this transfer  
9 reflects the use of the Mt. Hayes LNG facility for storage services (which is  
10 recovered through gas storage and transportation rates) and capacity  
11 requirements (which is recovered through delivery rates).<sup>16</sup>

12 13.1 Please provide the page(s) of the relevant FortisBC application which proposed  
13 this method, and possible alternatives, of allocating costs associated with the use  
14 of the Mt. Hayes LNG facility for storage services and capacity requirements.

15

16 **Response:**

17 This response also addresses BCUC IR 1.13.1.1.

18 The Mt. Hayes Storage and Delivery Agreement between FEVI and FEI (the Storage and  
19 Delivery Agreement) determined the cost allocation approach for the capacity assigned to FEI  
20 and the demand charges that FEI would pay to FEVI. Although the Storage and Delivery  
21 agreement was approved December 14, 2007 pursuant to Order No. C-9-07, the demand  
22 charge was not set at that time. FEVI, in its 2010-2011 Revenue Requirements and Rate  
23 Design Application (the 2010-2011 RRA), sought approval of the demand charges for the Mt.  
24 Hayes capacity to be assigned to FEI under the Storage and Delivery Agreement, and which  
25 would be charged to FEI's gas costs. FEVI also sought approval in the 2010-2011 RRA for the  
26 cost allocation methodologies relating to the remaining Mt. Hayes capacity held by FEVI  
27 recognizing that it provides transmission system capacity support and serves as a gas storage  
28 resource in the gas supply portfolio. The 2010-2011 Negotiated Settlement Agreement (NSP),  
29 approved pursuant to Order G-140-09, accepted the Storage and Delivery Agreement. As part  
30 of the NSP, agreement was reached on the forecast cost of service for 2010 and 2011, which  
31 included a cost allocation of the remaining Mt. Hayes capacity held by FEVI between delivery  
32 margin and gas costs.

33 The allocation of the costs associated with the use of the Mt. Hayes LNG facility for storage  
34 services and capacity requirements was set out in the FortisBC Energy Utilities Common Rates,  
35 Amalgamation and Rate Design Application, dated April 11, 2012 (the Common Rates

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<sup>16</sup> Exhibit B-1, p. 36.



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1 Application). Pages 212-216 of the Common Rates Application describes the FEU's proposal to  
2 continue the allocation of Mt. Hayes LNG costs into the Delivery Margin and Midstream gas  
3 costs as previously presented to the Commission, and also discusses an alternative  
4 methodology. Table 9.7 shows the allocated costs between delivery margin and midstream  
5 under the options considered.

6 In the Decision accompanied by Order G-21-14 on the FEU's Application for Reconsideration  
7 and Variance of Commission Order G-26-13, page 22, the Commission stated: "There is little  
8 disagreement among the parties with respect to implementing FEI's existing rate design  
9 methodologies on a transitional basis. The Commission Panel agrees and accepts the proposal  
10 put forward by the FEU for the temporary rate design once the amalgamation is legally  
11 effective."

12 Order G-21-14, at Directive 3 c), approved: "*The use of a combined gas portfolio for the*  
13 *Amalgamated Entity as described in Section 7.4.3 of the Original Application and the gas supply*  
14 *cost allocation methodology for rate setting purposes as described in Section 9.3.4 of the*  
15 *Original Application ...*" As referenced in section 9.3.4 of the Common Rates Application (i.e.  
16 the Original Application), only minor changes were proposed to the allocation of gas costs within  
17 the amalgamated gas supply commodity and midstream portfolios as part of that application.  
18 As discussed on pages 212-216, as noted above, no changes were proposed for the treatment  
19 of the Mt. Hayes LNG facility costs.

20 Finally, as noted in the response to BCUC IR 1.13.3.1, a review of the allocation and recovery of  
21 costs associated with both the Tilbury and Mt. Hayes LNG facilities will be considered in the  
22 comprehensive rate design application to be filed at the end of 2016.

23  
24

25

26 13.1.1 Please provide the page(s) of the accompanying Commission decision  
27 that addressed the allocation of costs for Mt. Hayes as described in the  
28 previous question.

29

30 **Response:**

31 Please refer to the response to BCUC IR 1.13.1.

32

33

34



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1           13.2   Please explain why the LNG Capacity Assignment is presented in the Application  
2                    as “Other Revenue.”

3  
4   **Response:**

5   The Mt. Hayes LNG facility includes rate base capital costs and operating costs which are  
6   embedded in the delivery margin of FEI – i.e. embedded in the Earned Return, Income Tax,  
7   Property Tax, Depreciation Expense and O&M Expense. The \$18.039 million capacity  
8   assignment is based on market valuation of avoided storage costs and transport costs on NW  
9   Natural pipe. To properly allocate the capacity assignment value of \$18.039 million to the  
10   midstream requires an equal offset to the Delivery Margin which is accomplished by crediting  
11   Other Revenue.

12   This is consistent with how FEI treats other intra-company cost assignments related to assets  
13   forming part of the Company’s rate base, such as the Southern Crossing Pipeline (SCP)  
14   transportation capacity held by the Company in the midstream for its own gas supply  
15   requirements. The costs are debited to the cost of gas and the offsetting credit is booked to  
16   other revenue.

17  
18

19  
20           13.2.1   Is the LNG Capacity Assignment classified as Other Revenue for  
21                    financial statement purposes? If no, please explain what it is classified  
22                    as.

23  
24   **Response:**

25   No, for financial statement purposes the amounts recorded as Other Revenue are included in  
26   the “Natural gas transmission and distribution” revenue line on the statement of earnings.

27  
28

29  
30           13.3   Please explain how the costs associated with the use of the Tilbury LNG facility  
31                    for storage services and capacity requirements are currently allocated.

32  
33   **Response:**

34   The Tilbury LNG Facility (Tilbury) was designed and constructed between 1969 and 1971, and  
35   was commissioned in 1971. Tilbury is primarily a peaking resource providing critical system



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1 capacity during extreme winter peaking events and provides system reliability and security of  
2 supply benefits. Tilbury has been consistently classified as demand-related in FEI's previous  
3 (1993, 1996, and 2001) rate design applications. In the 2001 rate design application, the total  
4 cost of service associated with Tilbury was included in the delivery margin and allocated based  
5 on peak day demand. All firm customers were allocated costs associated with Tilbury based on  
6 peak demand since all customers benefit from the peaking and operational flexibility that Tilbury  
7 provides.

8  
9

10

11 13.3.1 Is the proposed method for allocation of the costs associated with Mt.  
12 Hayes consistent with the treatment of costs associated with the Tilbury  
13 LNG facility?

14

15 **Response:**

16 FEI is not proposing any change from the existing treatment of costs associated with Mt. Hayes.

17 The approved allocation of costs between delivery and gas cost for Mt. Hayes is different than  
18 the Tilbury allocation of costs to delivery.

19 The Mt. Hayes cost allocation recognizes that the Mt. Hayes LNG facility provides system  
20 capacity for the Vancouver Island system (and indirectly to the coastal transmission system)  
21 and is a peaking and seasonal gas storage resource in the gas supply portfolio. Accordingly, as  
22 proposed in the FEVI (formerly TGVI) 2010-2011 RRA process, as well as in the FEU's  
23 Common Rates, Amalgamation and Rate Design Application, the Mt. Hayes costs are being  
24 allocated to both delivery margin and to midstream gas costs.

25 Review of the allocation and recovery of costs associated with the Mt. Hayes LNG facility will be  
26 considered in the comprehensive rate design application to be filed at the end of 2016.

27

28

29

30 13.3.1.1 If the methods are not consistent please justify the approach  
31 used to allocate the costs associated with the use of Mt.  
32 Hayes.

33



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1 **Response:**

2 Please refer to the response to BCUC IR 1.13.3.1.

3  
4

5

6 13.4 Please explain how the Core Market Administration Expense (CMAE) budget is  
7 allocated between gas costs and non-gas costs.

8

9 **Response:**

10 The Core Market Administration Expense (CMAE) is not allocated between gas costs and non-  
11 gas costs. The CMAE is allocated fully to gas costs and recovered via gas cost recovery rates.

12 As a result of the amalgamation of the FortisBC gas utilities, effective December 31, 2014, the  
13 CMAE is no longer required to be allocated between gas utilities. However, the CMAE is  
14 allocated between the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost  
15 Reconciliation Account (MCRA); the allocation is 30 percent to the CCRA and 70 percent to the  
16 MCRA, for recovery via the commodity rate and the midstream (storage and transport) rates,  
17 respectively.

18

19

20

21 13.4.1 Does the treatment of CMAE necessitate inclusion in "Other Revenue"?  
22 Please explain.

23

24 **Response:**

25 The treatment of CMAE costs does not necessitate inclusion in "Other Revenue" because in the  
26 absence of costs charged directly to CMAE they would be charged to O&M expense as period  
27 costs. In contrast, the costs of the Mt. Hayes LNG facility include rate base capital costs and  
28 operating costs which are embedded in the delivery costs of FEI, i.e. embedded in the Earned  
29 Return, Income Tax, Property Tax, Depreciation Expense and O&M Expense. The \$18.039  
30 million capacity assignment is based on market valuation of avoided storage costs and transport  
31 costs on NW Natural pipe. To properly allocate the capacity assignment value of \$18.039 million  
32 to the midstream requires an equal offset to the Delivery Margin which is accomplished by  
33 crediting Other Revenue.



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13.4.2 Would an allocation method similar to the CMAE budget be appropriate for Mt. Hayes? Please elaborate.

**Response:**

8 No, an allocation method similar to the CMAE budget would not be appropriate for Mt. Hayes.  
9 The CMAE costs are allocated 30 percent to the CCRA and 70 percent to the MCRA, for  
10 recovery via the gas cost recovery rates. The Mt. Hayes LNG facility is a midstream storage  
11 facility as well as a Transmission facility (in place of added Transmission Compression). As a  
12 midstream resource the \$18.039 million is debited to the MCRA and credited to delivery margin  
13 through Other Revenue. As an amalgamated entity, this is simply a reclassification entry.



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1 **E. OPERATIONS AND MAINTENANCE EXPENSE**

2 **14.0 Reference: O&M EXPENSE**

3 **Exhibit B-1-1: Section 6, Table 6.1, p. 37; Section 8.3.3, p. 59**

4 **Direct Allocation of Labour to Capital Projects**

5 In Table 6-1 on page 37 of the Evidentiary Update, FEI reports Total Gross O&M of  
6 \$271.235 million for 2015, and identifies \$32.548 million of Capitalized Overhead.<sup>17</sup>

7 14.1 Please explain whether FEI will also directly allocate some amount of labour  
8 and/or other expenses to CPCN and other capital projects in 2015, and explain  
9 how any directly allocated expenses are distinguished from capitalized overhead.

10

11 **Response:**

12 Labour and other expenses that are considered directly related to a specific identified capital  
13 project will be charged directly to that project (not allocated) and will form part of the direct  
14 capital cost of that associated asset.

15 Expenses that are charged directly to a project are separate and distinct from labour and other  
16 expenses that are incurred in support of the capital function of the organization, which are  
17 categorized as capitalized overhead. The Commission approved an overhead capitalization  
18 rate for FEI of 12 percent of Gross O&M in Order G-138-14.

19

20

21

22 14.2 If FEI directly allocates expenses to capital projects, please explain how FEI  
23 determines the amount of labour and/or other expenses to allocate to each  
24 project.

25

26 **Response:**

27 As explained in the response to BCUC IR 1.14.1, does not 'allocate' labour or other expenses to  
28 capital projects. Labour and other expenses that are considered directly related to a specific  
29 identified capital project will be charged directly to that project and will form part of the direct  
30 capital cost of that associated asset.

31 In the case of labour, an employee's timesheet will determine the basis for their direct charge to  
32 a specific identified capital project. The hours that an employee charges to a specific identified

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<sup>17</sup> Exhibit B-1-1, p. 37.



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1 capital project will be multiplied by their fully loaded charge-out rate to determine the dollars that  
2 are charged to that project.

3 In the case of expenses, the cost centre manager will specifically code each expense, charging  
4 to a specific capital project only those expenses that are directly related to that specific project.

5  
6

7  
8

14.2.1 Please provide the actual amount of O&M which was directly allocated  
to capital projects in 2013 and 2014, and the amount forecast to be  
directly allocated in 2015.

9  
10  
11

12 **Response:**

13 Other than Capitalized Overhead which is calculated as a fixed percentage of gross O&M (14  
14 percent in 2013, 12 percent in 2014 and 2015), there is no further allocation of O&M to capital  
15 projects. As explained in the responses to BCUC IRs 1.14.1 and 1.14.2, labour and other  
16 expenses that are considered directly related to a specific identified capital project will be  
17 charged directly to that project and will form part of the direct capital cost of that associated  
18 asset. These costs are not considered O&M expenses allocated to capital projects.

19  
20

21  
22

14.2.2 Please provide the actual amount of O&M directly allocated to each  
CPCN project in 2013 and 2014, and the amount forecast to be directly  
allocated to each CPCN project in 2015.

23  
24  
25

26 **Response:**

27 Please refer to the response to BCUC IR 1.14.2.1.

28  
29

30  
31



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1 FEI states that it applies Allowance for Funds Used During Construction (AFUDC) to  
2 projects that are greater than 3 months in duration and greater than \$50 thousand.<sup>18</sup>

3 14.3 Does FEI have a set of criteria which it uses to determine if, and how much,  
4 labour and other O&M is directly allocated to capital projects? Please discuss.

5

6 **Response:**

7 Other than Overheads Capitalized, which are determined formulaically as a percentage of  
8 Gross O&M (12 percent for 2014 and 2015), there is no further allocation of O&M (labour or  
9 expenses) to capital projects.

10 As explained in the response to BCUC IR 1.14.1, labour and other expenses that are  
11 considered directly related to a specific identified capital project will be charged directly (not  
12 allocated) to that project, forming part of the direct capital cost of that associated asset.

13 In order to determine the 'direct' applicability of labour and other expense to a specific identified  
14 capital project, FEI relies upon available guidance from US GAAP as well as the BCUC Uniform  
15 System of Accounts Prescribed for Gas Utilities.

16

---

<sup>18</sup> Exhibit B-1-1, p. 59.



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1 **15.0 Reference: O&M EXPENSE**

2 **Exhibit B-1: Section 6.3.2, pp. 40-41**

3 **Insurance**

4 FEI states:

5 The 2015 forecast is projected to increase by \$0.409 million or 6.5 percent from  
6 what was approved for 2014. This is forecast based on the average increase for  
7 the past five years, and this historical increase reflects both increase in premiums  
8 and increases in the value of assets...The forecast for 2015 assumes normal  
9 asset growth numbers.<sup>19</sup>

10 15.1 Please provide the average Actual increase in insurance expense based on the  
11 past five years actual results. Please provide the supporting calculations.

12 **Response:**

13  
14 The total average actual increase in insurance expense based on the 2010 to 2014 actual and  
15 2015 projected results on an FEI amalgamated basis is 7.05 percent. The supporting  
16 calculations are provided in the table below.

Total Insurance		% Increase from Prior Year
2010	\$4,720,072.78	
2011	\$5,013,699.86	6.2%
2012	\$5,424,933.87	8.2%
2013	\$5,877,251.11	8.3%
2014	\$6,198,000.00	5.5%

17

18

19

20

21 15.2 What was the percentage increase in the 2014 forecast insurance expense  
22 compared to the 2013 approved insurance expense? Please provide the  
23 supporting calculations.

24

---

<sup>19</sup> Exhibit B-1, pp. 40-41.

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1    **Response:**

2    The percentage increase for 2014 Forecast insurance expense compared to the 2013 Approved  
 3    insurance expense was 8.6 percent. The supporting calculations are provided below.

- 4    • The 2013 Approved expense was \$5.706 million for FEI, FEVI and FEW combined.  
 5    • The 2014 Projected insurance expense was \$6.198 million as shown in Table 6-3.  
 6    • \$6.198 million/\$5.706 million = 1.086.

7  
8

9

10        15.3    Given FEI's statement in the above preamble that the forecast assumes normal  
 11                asset growth numbers, is it reasonable to conclude that any increase in  
 12                insurance expense which is above the average historical rate of increase is due  
 13                to the increase in the value of individual assets? If no, please explain. If yes,  
 14                please explain why individual assets are increasing in value.

15

16    **Response:**

17    No, there are factors other than the historical rate of increase and the increase in the value of  
 18    the individual assets that influence insurance expense. Insurance premium forecasting is a  
 19    combination of what the market forecast for insurance premiums will be, the potential growth in  
 20    the company assets (replacement values not depreciated values) and other factors, such as  
 21    revenue and loss history. Insurance premiums are largely based on replacement values of  
 22    assets for property insurance (which represents over 80 percent of insurance cost). Premium  
 23    forecasting therefore needs to take into account replacement costs for existing assets, but also  
 24    capital growth for property asset values. Following is a chart of existing replacement cost asset  
 25    values for the last five years:

Year	Replacement Cost Values	% Increase/Decrease
<b>2010</b>	\$6,955,082,907	1.7%
<b>2011</b>	\$7,205,319,767	3.6%
<b>2012</b>	\$7,445,513,217	3.3%
<b>2013</b>	\$10,221,671,565*	13.7%
<b>2014</b>	\$10,513,176,863	2.9%

26    \* Adjustment in replacement cost values for underground pipe as a result of increase in cost of materials  
 27    in 2013 over 2012.

28



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1 **16.0 Reference: O&M EXPENSE**

2 **Exhibit B-1: Section 6.3.3, p. 41**

3 **Biomethane O&M**

4 FEI states: "The remainder of \$0.078 million is the O&M associated with interconnection  
 5 stations which pre-dated or were approved in Order G-210-13, which is recovered  
 6 through delivery rates."<sup>20</sup>

7 16.1 Please provide a breakdown of the remainder of \$0.078 million by  
 8 interconnection station.

9  
 10 **Response:**

11 The following table provides the 2015 forecast O&M for biomethane interconnect stations.

	Amount (\$000's)
INTERCONNECT STATIONS	O&M
Fraser Valley Biogas	\$ 13
Salmon Arm Landfill	13
Kelowna Landfill	13
Sea Breeze Farms	13
Dicklands Farm	13
Greater Vancouver Sewerage & Drainage District	<u>13</u>
Total	<u>\$ 78</u>

12

13 The Dicklands Farm and the GVS&DD projects are now planned to be completed in 2016 which  
 14 would result in a \$26 thousand reduction to the forecast O&M for 2015. Any variance from the  
 15 Commission Approved O&M Expense related to Biomethane will be captured in the Flow-  
 16 Through Deferral Account.

17

---

<sup>20</sup> Exhibit B-1, p. 41.

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1 **17.0 Reference: O&M EXPENSE**

2 **Exhibit B-1: Section 6.3.4, p. 41; Appendix B, p. 2**

3 **Natural gas for transportation**

4 FEI states: "While the forecast capital and O&M is included in the delivery cost of  
 5 service, the cost of service of fueling stations is offset by the rates recovered from  
 6 fueling station customers..."<sup>21</sup>

7 FEI further states: "While the forecast capital and O&M is included in the delivery cost of  
 8 service, the cost of service associated with the tankers is offset by the Tanker  
 9 Transportation Charge approved in Rate Schedule 46."<sup>22</sup>

10 17.1 Please provide the Actual 2014 and Forecast 2015 cost of service (O&M, taxes,  
 11 depreciation and amortization, and earned return) of the CNG and LNG fueling  
 12 stations and the Tanker Transportation Services.

13  
 14 **Response:**

15 Since FEI does not maintain separate accounting records for the earned return and income tax  
 16 on NGT assets, similar to the calculation of the forecast cost of service, the historic cost of  
 17 service is derived from the actual operating and capital costs and approved depreciation, tax  
 18 rates and rates of return. However, please note that the 2014 projected cost of service from the  
 19 Application is reflected below as 2014 actuals will not be complete until the end of April.

20 Finally, the offsetting recovery of these costs can be found in Table B-15 of Appendix B of the  
 21 application, specifically in the Revenue section as "Fueling Station" and "Tanker Rental". A  
 22 discussion on why the Tanker revenues are slightly less than tanker costs is provided in the  
 23 response to CEC IR 1.30.1.

	CNG/LNG Stations		LNG Tankers	
	2014P	2015F	2014P	2015F
<b>Cost of Service</b>				
O&M	\$ 477	\$ 768	\$ 155	\$ 158
Depreciation	482	606	92	184
Amortization	(79)	(59)	-	-
Income Taxes	(404)	(528)	(93)	(108)
Earned Return	634	851	59	59
<b>Total</b>	<b>\$ 1,110</b>	<b>\$ 1,638</b>	<b>\$ 213</b>	<b>\$ 293</b>

24

25

<sup>21</sup> Exhibit B-1, Appendix B, p. 2.

<sup>22</sup> Ibid

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1 **18.0 Reference: O&M EXPENSE**

2 **Exhibit B-1: Appendix B, pp. 7, 15**

3 **Tanker O&M forecast**

4 FEI is forecasting 2015 O&M expenses of \$0.058 million for LNG tanker trailers and  
5 \$0.100 million on Emergency Response and Preparedness (ERAP) coverage, which is  
6 required to respond to emergency situations related to the transport of LNG from FEI's  
7 facilities to customers' sites.<sup>23</sup>

8 FEI also states that it "has used 2014 projected tanker deliveries to forecast its 2015  
9 tanker rental revenues".<sup>24</sup>

10 18.1 Please discuss the services provided by the ERAP coverage.

11

12 **Response:**

13 Under Transport Canada Regulations, as the producer of a dangerous good, FEI is required to  
14 provide a registered Emergency Response Assistance Plan (ERAP) for the LNG product while  
15 in transit. The plans lay out the process, checklist and roles and responsibilities of those  
16 resources that would be involved in responding to an LNG emergency. Resources include LNG  
17 plant personnel that provide the role of technical advisors, and incident responders with support  
18 from Quantum Murray, an emergency response contractor that has been trained on LNG.

19 The \$0.100 million relates to the emergency response contractor retainer and training.

20

21

22

23 18.2 Please provide the 2013-2014 emergency response costs related to the transport  
24 of LNG from FEI's facilities to customers' sites by year.

25

26 **Response:**

27 In October 2013, FEI set up support from Quantum Murray for Emergency Response services  
28 as it relates to the transport of LNG to end use customers. ERAP coverage applies to  
29 geographic coverage and modes of transport (i.e. by road, rail, and marine) and is therefore not  
30 broken down by customer. The cost was \$17,666 in 2013 (for two months only) and \$99,333 in  
31 2014.

<sup>23</sup> Exhibit B-1, Appendix B, pp. 7, 15.

<sup>24</sup> Ibid.



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18.3 Please provide the increased number of tanker deliveries resulting from the 2015 LNG Demand Additions in Table B-4 of Appendix B in the Application.

5

6

7

**Response:**

8

As discussed in section 6.1.3 of Appendix B, FEI has used 2014 projected tanker deliveries to forecast its 2015 tanker rental revenues as demonstrated in Table B-14 below. This is because even with the forecasted increase in demand, FEI will not necessarily be providing the transportation service. Customers such as Ferus or ENN may provide their own tanker for pickup at FEI's LNG Facilities.

9

10

11

12

13

**Table B-14: Tanker Rental Revenue**

<b>Tanker Rental Revenue</b>	<b>2014P</b>		<b>2015F</b>	
Tanker Rental Deliveries	828	\$	828	
Rate (\$/Delivery)	\$	254	\$	259
Total Tanker Rental Revenue (\$ millions)	\$	0.210	\$	0.215

14

15



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1 **19.0 Reference: O&M EXPENSE**

2 **Exhibit B-1: Section 6.3.5, Table 6-5, p. 42; Appendix B, Table B-15,**  
3 **p. 16**

4 **Rate Schedule 46 O&M**

5 Table 6-5 shows a 2015 forecast O&M amount of \$1.415 million for Rate Schedule 46.<sup>25</sup>

6 Table B-15 in Appendix B shows a 2015 forecast O&M amount of \$0.926 million.<sup>26</sup>

7 19.1 Please explain why the 2015 forecast O&M in Table B-15 is \$0.489 million less  
8 than the 2015 forecast O&M in Table 6-5.

9

10 **Response:**

11 The Rate Schedule 46 O&M of \$1.415 million shown on line 14 of Table 6-5 is not comparable  
12 to the O&M discussed in Appendix B and shown in Table B-15.

13 Line 14 of Table 6-5 shows the forecast O&M of \$1.415 million required at the Tilbury and Mt.  
14 Hayes plants to produce LNG that can be dispensed (sold) under Rate Schedule 46. In contrast,  
15 the O&M forecast of \$0.926 million in Table B-15 reflects the forecast O&M that is required to  
16 operate and maintain FEI's existing and forecast CNG and LNG fueling stations, tanker trailers  
17 for NGT and emergency response action plan.

18 As shown in Table 6-3, the two forecast amounts are additive. The Rate Schedule 46 O&M  
19 amount of \$1.415 million is shown on Line 5 of Table 6-3 and the NGT O&M of \$0.926 million is  
20 shown on Line 4 of Table 6-3. Both are included in the \$35.361 million of 2015 forecast O&M  
21 shown in line 7 of Table 6-3.

22

23

24

25 19.2 Please explain and quantify how the three categories of O&M in Table B-15 (i.e.  
26 Fueling Stations; Tankers; ERAP) relate to the cost breakdown in Table 6-5.

27

28 **Response:**

29 Please refer to the response to BCUC IR 1.19.1.

30

<sup>25</sup> Exhibit B-1, p. 42.

<sup>26</sup> Exhibit B-1, Appendix B, p. 16.

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1   **20.0 Reference: O&M EXPENSE**

2                           **Exhibit B-1: Section 3.5.3, p. 26; Section 6.3.5, pp. 41-42**

3                           **Incremental O&M to support rate schedule 46 revenues**

4           FEI states:

5                   Although FEI had assumed a gradual build-up of activities averaging 1,500 GJ  
6                   per day and only utilizing the Tilbury LNG facility to supply LNG for 2014, the full  
7                   cost of these activities was not reflected in the forecast or the approved O&M.  
8                   The 2014 projected amount of \$0.550 million does reflect that level of activities.<sup>27</sup>

9           20.1 Please provide the actual annual and average GJ per day supply of LNG from  
10           Tilbury in 2014.

11  
12   **Response:**

13   The actual annual supply of LNG from Tilbury in 2014 was 517,289 GJ. The average supply  
14   was 1,417 GJ/day (based on 365 days).

15  
16

17  
18           20.2 Please explain why Tilbury costs are forecast to increase by 248 percent (\$1.365  
19           million/\$0.550 million) from 2014 to 2015, while the supply is forecast to increase  
20           by 203 percent (3,040 GJ per day/ 1,500 GJ per day).

21  
22   **Response:**

23   The relationship between Tilbury operational costs and LNG supply is not linear. The costs to  
24   supply LNG for Rate Schedule 46 are incremental to the regular O&M costs for operating the  
25   Tilbury facility as a peaking storage facility. In 2014, FEI was able to leverage existing  
26   resources to provide Rate Schedule 46 service resulting in reduced incremental costs. In 2015,  
27   the higher supply forecast will require more liquefaction which increases O&M; however, these  
28   additional O&M costs are offset by the higher Rate Schedule 46 recoveries.

29

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<sup>27</sup> Exhibit B-1, pp. 41-42



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1 **F. RATE BASE**

2 **21.0 Reference: FORMULA CAPITAL EXPENDITURES**

3 **Exhibit B-1: Section 7.2.1, p. 46; Exhibit B-1-1, Section 11, Schedule**  
4 **28**

5 **Calculation of Contributions in Aid of Construction (CIAC)**

6 FEI states that the PBR formula for Other Capital is applied to CIAC and shows a CIAC  
7 amount of \$5.526 million for FEI for 2014 (excluding FEVI and FEW) and \$6.448 million  
8 for 2015.<sup>28</sup>

9 Schedule 28 in Section 11 attributes \$5.994 million of the 2015 CIAC to Distribution  
10 contributions and \$0.454 million to Transmission contributions.<sup>29</sup>

11 21.1 Please explain how the \$5.526 million of CIAC for FEI for 2014 was determined,  
12 and show the calculation.

13

14 **Response:**

15 The 2014 CIAC was determined by applying the approved PBR formula to the CIAC included in  
16 2013 base capital as follows:

17 
$$\$5.526 \text{ million} = \$5.492^{30} \text{ million} \times (1 + 0.36\%) \times (1 + 0.26\%)$$

18 \$5.492 million equals the CIAC included in the 2013 Base, 0.36 percent equals the 2014 (I – X)  
19 factor and 0.26 percent equals the 2014 growth component included in the PBR formula.

20 The amount of \$5.526 million is also shown on Schedule 26 Line 14 Column 4 of Appendix A to  
21 FEI's 2014 Delivery Rates Compliance Filing that was approved by Order G-164-14.

22

23

24

25 21.1.1 What is the Actual (or projected actual) amount of CIAC for FEI in  
26 2014?

27

<sup>28</sup> Exhibit B-1, p. 46.

<sup>29</sup> Exhibit B-1-1, Section 11, Schedule 28.

<sup>30</sup> FEI Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Vol 1, p. 61, Table B6-6: 2013 Base Capital (\$ thousands).



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1 **Response:**

2 The FEI 2014 projected CIAC is \$4.030 million.

3  
4

5

6 21.1.2 How were the amounts for 2014 of \$0.853 million of CIAC for FEVI and  
7 \$0.017 million of CIAC for FEW determined?

8

9 **Response:**

10 The 2014 amount for FEVI is the CIAC amount as approved in Order G-65-14 and included in  
11 FEI's proposal to include FEVI and FEW in its PBR Plan as shown in Table 4 of that application.

12 The 2014 amount for FEW is the projected amount for 2014 that was included in FEI's proposal  
13 to include FEVI and FEW in its PBR Plan as shown in Table 5 of that application.

14 As stated on page 45 of this Application, FEI will update its financial schedules for the approved  
15 addition to the base capital once the amounts for FEVI and FEW have been determined. The  
16 update of capital expenditures will include the approved CIAC additions for FEVI and FEW.

17  
18

19

20 21.2 If the Commission has explicitly approved the use of the PBR formula for Other  
21 Capital to calculate CIAC, please identify where it has done so. Please also  
22 provide the Section of FEI's 2014-2018 PBR Application which discusses this  
23 treatment of CIAC.

24

25 **Response:**

26 The Commission states on page 215 of the PBR Decision: "Accordingly, the Panel approves  
27 FEI's proposed 2013 Base Capital, for use in determining formulaic 2014 capital, as applied for,  
28 subject to any further change directed in this Decision." Since there was no further change  
29 directed regarding the treatment of CIAC in a different manner than proposed by FEI, the  
30 Commission approved the inclusion of the CIAC in the Sustainment and Other Capital  
31 calculation.

32 FEI's proposed treatment of CIAC was shown on pages 61 and 65 of FEI's PBR Application.  
33 Specifically, the total 2013 Base for Sustainment and Other Capital in Table B6-8 of \$102,714



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1 thousand was equal to the total of the Sustainment, Other and CIAC categories from Table B6-  
2 6.

3 The topic of whether CIAC should be separated between growth and other capital was explored  
4 in BCUC IRs 3.15.1 through 3.15.4. As stated in response to BCUC IR 3.15.1, CIAC was  
5 shown on one line in Table B6-6 and it was all allocated to the Sustainment and Other category  
6 in computing the capital formula for Table B6-8.

7

8

9

10

11 21.2.1 If the Commission has not explicitly approved the use of the PBR  
12 formula for Other Capital to calculate CIAC, please explain why FEI  
13 considers this to be the appropriate methodology.

14

15 **Response:**

16 The responses to BCUC IRs 3.15.1 and IR 1.3.15.2 in the PBR proceeding addressed this topic.  
17 In those responses, FEI demonstrated that although in most years more CIAC related to  
18 sustainment capital than to growth capital, the proportions vary. The total Growth CIAC over the  
19 years 2007 to 2013 was approximately \$16 million whereas the total Sustainment CIAC over the  
20 same period of time was approximately \$29 million.

21 For simplicity, FEI proposed including all of the CIAC in the sustainment and other capital  
22 calculation. As demonstrated in BCUC IR 1.3.15.1 in the PBR proceeding, the effect of  
23 calculating an estimate of the CIAC related to growth capital expenditures using the growth  
24 capital formula was immaterial when compared to the method that has been approved. The  
25 formula-driven capital spending amount would have decreased by \$3 thousand for 2014 under  
26 the alternative approach.

27

28

29

30 21.2.2 Please break out the \$5.994 million of Distribution contributions for 2015  
31 between the amount related to Growth Capital expenditures and the  
32 amount related to Other Capital expenditures, and explain the allocation  
33 basis that FEI used.

34



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1 **Response:**

2 The formula distribution and transmission contributions for 2015 have been calculated in the  
 3 same manner as the 2014 formula distribution and transmission contributions and result in  
 4 \$1.924 million in the Growth Capital Expenditures and \$4.070 million in the Sustainment and  
 5 Other Capital Expenditures categories of formulaic Distribution contributions.

6 More specifically, the 2015 amounts were determined by using FEI Mainland's total 2014  
 7 formulaic CIAC of \$5.526 million, adding to that FEW and FEVI's CIAC of \$0.853 million and  
 8 \$0.017 million respectively, then applying the 2015 capital formula to the total to come to the  
 9 2015 formulaic CIAC of \$6.448 million. The \$6.448 million was then allocated to distribution  
 10 growth, distribution other and transmission contributions based on FEI's 2013 relative  
 11 percentages of the aforementioned categories to total CIAC. Please note that these are the  
 12 same percentages that were used to determine the allocation of 2014 formula contributions  
 13 amongst the CIAC categories. The calculation is shown below.

Line	Particulars	(\$000)	Notes
1			
2	2014 FEI Formula	\$ 5,526	G-138-14 Compliance Filing, Appendix A, Schedule 26, Line 14, Column 4
3	Add: FEVI 2014 Approved	853	G-65-14 Compliance Filing, Appendix 1, Schedule 27, Line 10, Column 4
4	Add: FEW 2014 Approved	17	2015 FEI Interim Rates Application, Appendix B3 (FEW G-47-14), Schedule 44, Line 5, Column 4
5	Total 2014 Formula Contributions	<u>\$ 6,396</u>	
6			
7	Net Inflation Factor	0.203%	Section 11, Schedule 18
8	Customer Growth	0.614%	Section 11, Schedule 18
9			
10	<b>2015 Formula Contributions</b>	<b><u>\$ 6,448</u></b>	
11			
12	<u>Percentage of 2013 Contributions</u>		
13	Distribution Growth	30%	Embedded in 2014 formula calculations
14	Distribution Other	63%	Embedded in 2014 formula calculations
15	Transmission	7%	Embedded in 2014 formula calculations
16			
17	<u>2015 Formula Contributions</u>		
18	Distribution Growth	\$ 1,924	Line 10 x Line 13
19	Distribution Other	4,070	Line 10 x Line 14
20	Transmission	454	Line 10 x Line 15
21		<u>\$ 6,448</u>	

14

15

16

17





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<u>Line</u>	<u>Particulars</u>	<u>(\$000)</u>	<u>Reference</u>
1			
2	<b>Growth CIAC calculated using Growth Capital formula</b>		
3	2014 FEI CIAC allocated to growth capital	\$ 1,649	
4	2014 FEVI CIAC forecast for growth capital	555	
5	2014 FEW CIAC forecast for growth capital	17	
6	Total	\$ 2,221	Sum of Lines 3 to 5
7	2014 Base Service Line Additions (SLA's)	10,156	Section 11, Schedule 18
8	2014 growth capital CIAC per SLA (\$/SLA)	\$ 218.69	Line 6 / Line 7 x 1000
9			
10	2015 Service Line Addition growth	-5.615%	Section 11, Schedule 18
11	2015 Net Inflation Factor	0.203%	Section 11, Schedule 18
12			
13	2015 SLA's	9,586	Line 7 x (1 + Line 10)
14	2015 growth capital CIAC per SLA (\$/SLA)	\$ 219.13	Line 8 x (1 + Line 11)
15	2015 CIAC for growth capital	\$ 2,101	Line 13 x Line 14 / 1000
16			
17	<b>Growth CIAC calculated using Other Capital formula (offset)</b>		
18	Average Customer Growth	0.614%	Section 11, Schedule 18
19	Total 2014 growth capital CIAC	\$ (2,221)	- Line 6
20	2015 growth capital CIAC	(2,239)	Line 19 x (1 + Line 11) x (1 + Line 18)
21			
1	22 <b>Net difference between CIAC calculation methods</b>	<b>\$ (139)</b>	Line 15 + Line 20

2  
3

4

5 21.3 Please clarify whether the amount of CIAC calculated using the PBR formula is  
 6 the amount taken into rate base for that year and used as the base amount for  
 7 calculating the next year's CIAC, or if the actual or projected amount of CIAC in  
 8 the year is used.

9

10 **Response:**

11 The CIAC that reduces rate base each year is calculated by applying the PBR formula to the  
 12 previous year's CIAC, which was calculated using the previous year's PBR formula. This is the  
 13 approved methodology to calculate capital expenditures under the PBR Plan.



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1 An exception to this is that 2015 CIAC was derived by applying the 2015 PBR formula to the  
2 2014 CIAC of FEI, plus FEVI and plus FEW, where FEI's 2014 CIAC was derived by the 2014  
3 PBR formula and both FEVI's and FEW's 2014 CIAC were derived with a forecast<sup>31</sup>.

4  
5

6  
7

21.3.1 If the amount of CIAC calculated using the PBR formula is trued up to  
8 actual going forward, please explain how this done and why FEI  
9 believes this true-up is appropriate.

10  
11

**Response:**

12 CIAC is not trued up to actual each year through the term of the PBR.

13  
14

15  
16

21.4 Given the variations experienced year to year with CIAC, would it be more  
17 appropriate to remove CIAC from the PBR formula? Please discuss.

18  
19

**Response:**

20 No it would not be more appropriate. The CIAC that are received are for specific capital  
21 projects undertaken in the Growth and Sustainment capital categories. The variations in CIAC  
22 experienced are related to similar variations in the capital expenditures that are made. If the  
23 capital expenditures themselves are under the PBR formula, then the CIAC that are received for  
24 those same projects should be treated in the same manner. There is no basis to isolate the  
25 CIAC for a different treatment than is applied to the overall growth and sustainment capital  
26 portfolio, since FEI manages the entire portfolio in the same manner.

27

---

<sup>31</sup> FEW and FEVI were not under PBR in 2014.

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1   **22.0 Reference: TANKER CAPITAL EXPENDITURE FORECAST**

2                           **Exhibit B-1: Appendix B, p. 14**

3                           **Tankers for marine load**

4           FEI states:

5                           FEI purchased an LNG tanker in 2014 at a capital cost of \$0.280 million and the  
6                           five tankers that would be purchased in 2015 will be of similar storage size and  
7                           capability as the tanker purchased in 2014. Four LNG tankers will be used to  
8                           service the marine load, and will have to be customized to provide truck-to-ship  
9                           bunkering to BC Ferries and Seaspan at an approximate capital cost of \$0.320  
10                           million each.<sup>32</sup>

11           22.1 Please confirm, or explain otherwise, that the cost of one customized tanker used  
12                           in truck-to-ship bunkering is \$0.600 million (\$0.280 million plus \$0.320 million).

13  
14   **Response:**

15   Not confirmed. The specialized tankers that will be used for the truck-to-ship bunkering are  
16   forecasted to cost \$0.320 million each, which is \$0.040 million more than the LNG tankers FEI is  
17   using to provide transportation service to its trucking customers. The increased cost is due to  
18   the installation of onboard pumping equipment and other controls that are required to deliver  
19   LNG to the marine vessels. However, marine offload design requirements are still being  
20   finalized and final costs are yet to be determined.

21  
22

23  
24           22.2 Given the higher cost of the tankers being used for marine loads, will FEI charge  
25                           a higher rate (\$/delivery) for the tankers used in truck-to-ship bunkering? Please  
26                           explain why, or why not.

27  
28   **Response:**

29   Should the final cost of the specialized tankers for marine loads be much higher than FEI's  
30   standard fleet, FEI would consider a specialized rate for the marine bunkering tankers taking  
31   into account the capital cost, O&M and utilization specific for this type of customer.

32

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<sup>32</sup> Exhibit B-1, Appendix B, p. 14.

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1   **23.0 Reference: DEFERRAL ACCOUNTS**

2                           **Exhibit B-1: Section 7.5, p. 49**

3                           **Application Cost Deferral Accounts**

4           23.1 Please provide the following information in tabular form for all application cost  
5           deferral accounts which have been approved/established for the years 2012,  
6           2013, 2014 and forecast 2015:

- 7                           • Forecast application cost spending at the time of the deferral account  
8                           request;
- 9                           • Actual application cost spending;
- 10                          • Length of proceeding, including time to prepare application;
- 11                          • Type of proceeding, including number of rounds of IRs and whether the  
12                          hearing process was written/oral/SRP/NSP;
- 13                          • Percentage of actual application costs related to consultant fees, legal fees,  
14                          internal FEI labour resources, Commission costs, PACA reimbursements,  
15                          and other.

16

17   **Response:**

18   The requested information for each of various deferrals accounts that were  
19   approved/established in 2012, 2013, 2014 and forecast 2015 are provided below. To clarify,  
20   “forecast spending” provided below are the amounts, excluding AFUDC, that were included in  
21   customer rates in the respective years. For example, if an account was non-rate base in 2011  
22   and transferred to rate base in 2012, the 2012 column below shows the total cumulative  
23   additions from 2011 and 2012 that were included in rate base in 2012. Further, the “actual  
24   spending” shown in 2012 includes any prior year additions as well.

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2012-2013 FEU RRA	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$1,250	\$0	\$0	\$0	\$1,250
Actual Spending (\$000s)	\$1,561	\$0	\$0	\$0	\$1,561
Consultant Fees	15%				15%
Legal Fees	31%				31%
Internal Labour	0%				0%
Commission Costs	25%				25%
PACA Reimbursements	23%				23%
Other	6%				6%
Length of Proceeding	<ul style="list-style-type: none"> <li>11.4 months duration from filing date of May 5, 2011 to Decision G-44-12 dated April 12, 2012</li> <li>preparation time prior to filing is estimated to have taken place most intensively 6 months in advance of filing</li> </ul>				
Type of Proceeding	Oral public hearing including 1,665 IRs in 4 rounds (3 rounds plus 1 supplemental round)				

1

2014 FEU LTRP	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$70	\$200	\$40	\$0	\$310
Actual Spending (\$000s)	\$0	\$0	\$117	\$0	\$117
Consultant Fees			0%		0%
Legal Fees			49%		49%
Internal Labour			0%		0%
Commission Costs			46%		46%
PACA Reimbursements			0%		0%
Other			5%		5%
Length of Proceeding	<ul style="list-style-type: none"> <li>8.4 months duration from filing date of March 25, 2014 to Decision G-189-14 dated December 3, 2014</li> <li>preparation time prior to filing is estimated to have taken place most intensively 6 months in advance of filing</li> </ul>				
Type of Proceeding	Written process with 948 IRs in 2 rounds				
Notes	PACA amounts approved at \$55,351.18 and Commission direct cost invoices received for January 2015 have not yet been recorded in actual spending. FEI does not know whether all Commission direct cost invoices have been issued or if further ones will be received in 2015 related to this proceeding.				

2

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2014-2019 FEI PBR	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$0	\$0	\$1,590	\$0	\$1,590
Actual Spending (\$000s)	\$0	\$590	\$1,109	\$0	\$1,699
Consultant Fees		37%	9%		19%
Legal Fees		42%	34%		36%
Internal Labour		1%	0%		0%
Commission Costs		18%	15%		16%
PACA Reimbursements		0%	42%		28%
Other		2%	0%		1%
Length of Proceeding	<ul style="list-style-type: none"> <li>15.3 months duration from filing date of June 12, 2013 to Decision G-138-14 dated September 15, 2014</li> <li>preparation time prior to filing is estimated to have taken place most intensively 8 months in advance of filing</li> </ul>				
Type of Proceeding	Oral public hearing with 3,551 IRs in 3 rounds				
Notes	PACA amounts and Commission direct cost invoices for the Reconsideration process and the Capital Exclusion process will still be received in 2015 and possibly 2016.				

1

BCUC GCOC Stages 1 & 2	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$0	\$0	\$2,194	\$0	\$2,194
Actual Spending (\$000s)	\$1,868	\$326	\$29	\$0	\$2,223
Consultant Fees	47%	97%	(55%)		53%
Legal Fees	27%	1%	0%		23%
Internal Labour	0%	0%	0%		0%
Commission Costs	0%	0%	0%		0%
PACA Reimbursements	24%	0%	155%		22%
Other	2%	2%	0%		2%
Length of Proceeding	<ul style="list-style-type: none"> <li>Stage 1 was 14.6 months duration from the start of the proceeding on February 28, 2012 to Decision G-75-13 dated May 10, 2013</li> <li>Stage 2 was 12.3 months duration from the start of the proceeding on March 22, 2013 to Decision G-47-14 dated March 25, 2014</li> <li>Preparation time prior to filing is estimated to have taken place 2-3 months in advance of the commencement of each stage in the process</li> </ul>				
Type of Proceeding	<ul style="list-style-type: none"> <li>Stage 1 was an oral public hearing with 956 IRs in 2 rounds</li> <li>Stage 2 was a written process with 614 IRs in 2 rounds</li> </ul>				

2

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FEU Amalgamation & RDA	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$0	\$0	\$1,553	\$0	\$1,553
Actual Spending (\$000s)	\$1,295	\$258	\$125	\$0	\$1,678
Consultant Fees	37%	0%	6%		29%
Legal Fees	24%	51%	78%		32%
Internal Labour	12%	2%	0%		10%
Commission Costs	8%	51%	1%		14%
PACA Reimbursements	4%	12%	15%		6%
Other	15%	(16%)	0%		9%
Length of Proceeding	<ul style="list-style-type: none"> <li>28.3 months duration from initial filing date of November 1, 2011 to Reconsideration Decision G-21-14 dated February 26, 2014</li> <li>preparation time prior to filing is estimated to have taken place most intensively 6 months in advance of filing</li> </ul>				
Type of Proceeding	Written process with 1,199 IRs in 4 rounds total (2 rounds in initial proceeding, 2 rounds in reconsideration proceeding)				
Notes	Commission direct cost invoices received for January 2015 have not yet been recorded in actual spending. FEI does not know whether all Commission direct cost invoices have been issued or if further ones will be received in 2015 related to this proceeding.				

1

FEI Rate Schedule 16	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$0	\$0	\$128	\$0	\$128
Actual Spending (\$000s)	\$55	\$73	\$29	\$0	\$157
Consultant Fees	0%	0%	0%		0%
Legal Fees	29%	63%	0%		40%
Internal Labour	0%	0%	0%		0%
Commission Costs	35%	37%	0%		29%
PACA Reimbursements	36%	0%	100%		31%
Other	0%	0%	0%		0%
Length of Proceeding	<ul style="list-style-type: none"> <li>8.4 months duration from initial filing date of September 24, 2012 to Decision G-88-13 dated June 4, 2013</li> <li>Preparation time prior to filing is estimated to have taken place most intensively 3-4 months in advance of filing</li> </ul>				
Type of Proceeding	Written process with 833 IRs in 2 rounds				

2



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2014 FEVI RRA	2012	2013	2014	2015	Total
Forecast Spending (\$000s)	\$0	\$0	\$50	\$0	\$50
Actual Spending (\$000s)	\$0	\$38	\$90	\$0	\$128
Consultant Fees		0%	0%		0%
Legal Fees		50%	51%		51%
Internal Labour		0%	0%		0%
Commission Costs		16%	23%		21%
PACA Reimbursements		0%	26%		18%
Other		34%	0%		10%
Length of Proceeding	<ul style="list-style-type: none"> <li>8 months duration from initial filing date of September 25, 2013 to Decision G-65-14 dated May 23, 2014</li> <li>Preparation time prior to filing is estimated to have taken place most intensively 3-4 months in advance of filing</li> </ul>				
Type of Proceeding	Written process with 801 IRs in 2 rounds				

1  
2

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1   **24.0 Reference: DEFERRAL ACCOUNTS**

2                           **Exhibit B-1, Section 7.5.1.1, p. 50**

3                           **New Accounts – 2016 Cost of Capital Application**

4           FEI states that it has estimated \$0.500 million in application costs.<sup>33</sup>

5           FEI further states:

6                           To the extent possible, past practice has been to align the recovery period for  
7                           regulatory application cost deferral accounts with the term to which the decisions  
8                           apply. As the term over which the Cost of Capital decision will be in place is  
9                           unknown at this time, FEI will request an amortization period for this account in  
10                          an upcoming Annual Review filing.<sup>34</sup>

11           24.1 Please provide a breakdown of the \$500 thousand in estimated application costs  
12                          amongst the cost items described on page 50 of the Application.

13  
14    **Response:**

15    There are many uncertainties with respect to the regulatory costs that will be incurred for the  
16    Cost of Capital filing directed by G-75-13. These include:

- 17           • The extent of the regulatory review process the Commission intends. If an oral hearing  
18                          is ordered, all cost categories will be significantly higher;
- 19           • Whether the Commission levy will cover the Commission's participation as it did for the  
20                          2012 Generic Cost of Capital (2012 GCOC) Process or whether the Commission will  
21                          issue direct cost invoices to FEI;
- 22           • Whether the Commission or Interveners will engage consultants or experts; and
- 23           • Whether the Commission will apportion Intervener PACA among all utilities that set their  
24                          ROE off the benchmark as was done for the 2012 GCOC.

25  
26    FEI's breakdown of the estimated \$500 thousand, is as follows:

---

<sup>33</sup> Exhibit B-1, p. 50.

<sup>34</sup> *ibid*



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Description	Estimate Amount
Commission Costs	\$150,000
Intervener PACA	\$210,000
FEI Experts/Consultants	\$70,000
Legal Costs	\$60,000
Other / Miscellaneous	\$10,000
	<b>\$500,000</b>

1  
2 As with all deferral accounts, only actual costs incurred will be recorded in the deferral account  
3 and recovered from customers.

4  
5

6  
7 24.2 How much additional application costs does FEI expect to incur during 2016 and  
8 what types of activities will these costs be related to?

9

10 **Response:**

11 FEI has anticipated that the bulk of the \$500 thousand estimated will be incurred in 2015;  
12 however, that will be dependent on the regulatory review process and timing determined by the  
13 Commission, and when a decision will be issued.

14  
15

16  
17 24.2.1 What does FEI estimate its total application cost spending will be on this  
18 proceeding?

19

20 **Response:**

21 Please refer to the response to BCUC IR 1.24.1.

22  
23

24

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1           24.3   Please describe the work which will be performed by FEI's consultant on this  
2                    application and provide the estimated number of hours the consultant is expected  
3                    to spend on this application in 2015.

4  
5    **Response:**

6    FEI has retained an independent expert on cost of capital who will provide testimony related to  
7    cost of capital matters including but not limited to ROE, business risk, capital structure,  
8    jurisdictional and industry analysis, and automatic adjustment mechanisms. It is estimated that  
9    the cost of capital expert will spend 100-150 hours on this application in 2015, but this estimate  
10   is subject to the regulatory review process determined by the Commission, the extent to which  
11   interveners participate in the process, including the filing of evidence that requires rebuttal  
12   evidence, and other factors beyond FEI's control.

13

14

15

16

17           24.4   Please explain how FEI allocates time spent by its internal resources, such as its  
18                    Regulatory department staff, on preparation of applications. Does any of that  
19                    time/cost get allocated to the application cost deferral account? If yes, please  
20                    explain why this is appropriate.

21

22    **Response:**

23    Time or cost for time spent by internal resources does not get allocated or charged to the  
24    application cost deferral but remains in O&M.

25

26

27

28           24.5   Did FEI consider filing for approval of this deferral account at the time of filing the  
29                    associated application? Please discuss.

30

31    **Response:**

32    Yes, FEI considered filing for approval of this deferral account at the time of filing the associated  
33    application, but given the timing of this Annual Review process and that costs are expected to  
34    be incurred in 2015, it is more appropriate and more efficient to apply for approval in this rate  
35    setting process.



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1 FEI's practice for general applications that are known and directed by a Commission Order,  
2 such as the upcoming Cost of Capital, Long Term Resource Plan and Rate Design applications,  
3 is to seek, when possible, approval of deferral accounts at the earliest opportunity. This  
4 practice provides transparency to the Commission and Interveners. Further, since FEI's  
5 external auditors request evidence of the approval of deferral accounts and the costs for these  
6 applications will be incurred through 2015, FEI requires approval in advance of year-end.

7  
8

9

10 24.6 Please discuss the reasonability of aligning the recovery period for regulatory  
11 application cost deferral accounts to the length of time it takes to conclude the  
12 proceeding, as opposed to the term to which the decision applies.

13

14 **Response:**

15 FEI does not believe it is reasonable or practical to align the recovery period for regulatory  
16 application cost deferral accounts with the length of time it takes to conclude the proceeding.  
17 There are two reasons:

18 1. There should be some causal relationship between the recovery period and the benefits  
19 of the proceeding. The benefits of the proceeding relate to the time period that the  
20 decision is in effect. The costs incurred are not related to the proceeding time, as the  
21 decision has not yet been made. The duration of a proceeding is affected by many  
22 circumstances including participant schedules, Commission resources, and other  
23 ongoing Commission processes. Further, the duration of a proceeding for a decision  
24 which is in force for multiple years may be the same or less than the duration of a  
25 proceeding for a decision which is in force for a much shorter period.

26 2. The proposed approach is not feasible. In almost every case, the length of proceeding  
27 is not known until after it has concluded, and costs are not known until after a decision is  
28 reached and invoices are received. There is no way to go back and retroactively  
29 amortize the deferral account over the period of time that the proceeding was in force.

30

31 FEI believes that it is most reasonable and that it is accepted regulatory practice for the  
32 recovery term of regulatory application cost deferral accounts to align with the term over which  
33 the decisions apply. This is consistent with the principle that the amortization period for a  
34 deferral account should consider the timing of associated benefits.

35

36



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1  
2           24.7   Does FEI agree that as part of the determination in subsequent annual reviews  
3                   regarding the recovery period for this, or other new deferral accounts, the  
4                   Commission should also be reviewing whether or not the balance in the deferral  
5                   account should be recovered, in whole or in part, from ratepayers? Please  
6                   discuss.

7  
8           **Response:**

9           FEI's regulatory application costs have been consistently and repeatedly found to be  
10           recoverable from customers by the Commission. FEI does not believe that the Commission  
11           needs to or should consider afresh whether regulatory application costs should be recovered  
12           from ratepayers in each annual review. While the balances in the accounts will be reviewed by  
13           the Commission, in law the balances in the deferral accounts are presumed to be prudent and  
14           recoverable from ratepayers barring a finding of imprudence in accordance with the prudence  
15           test endorsed by the courts.

16  
17  
18  
19           24.7.1   Please discuss whether FEI considers Commission approval of the  
20                   establishment of a deferral account to also mean approval of recovery  
21                   of the deferral account balance from ratepayers and explain the  
22                   rationale for why or why not FEI believes this to be the case.

23  
24           **Response:**

25           FEI does not consider Commission approval of the establishment of a deferral account to also  
26           mean approval of recovery of the deferral account balance from ratepayers. FEI applies to the  
27           Commission for recovery of the balances in its deferral accounts as part of its revenue  
28           requirement applications. Please refer to the response to BCUC IR 1.24.7.

29

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1   **25.0 Reference: DEFERRAL ACCOUNTS**  
2                                   **Exhibit B-1: Section 7.5.1.2, p. 50**  
3                                   **New Accounts – 2017 Rate Design Application**

4           FEI states on page 50 of the Application:

5                                   Based on historical experience, the December 31, 2017 balance in this deferral  
6                                   account is expected to be in the range of \$2.5 million to \$3 million, with the  
7                                   majority of the costs expected to be incurred in 2016. Additions to the deferral  
8                                   account in 2015 are forecast to be \$0.250 million and are related to forecast  
9                                   consultant costs and participant funding associated with stakeholder  
10                                  workshops.<sup>35</sup>

11           25.1 Please describe the nature of the work expected to be performed by consultants  
12                                   on the rate design application in 2015, the estimated number of hours for  
13                                   consultant time, and the percentage of the \$250 thousand forecast deferral  
14                                   account addition that is expected to be related to consultant costs.

15  
16    **Response:**

17    This response also addresses CEC IR 1.37.1.

18    FEI has not yet engaged a consultant for the 2017 Rate Design Application; however, the nature  
19    of the work performed by consultants in 2015 is expected to be related to scoping discussions, a  
20    review of the preliminary results from the various supporting studies and allocation factors and  
21    discussions and analysis regarding other potentially applicable studies and industrial customer  
22    rate design. In this regard, FEI has forecast approximately 550 hours of consultant time in  
23    2015, with this work expected to commence late in the second quarter of the year. This  
24    represents approximately 66 percent of the forecast deferral account addition in 2015.

25    The 2017 Rate Design Application costs deferral account will only capture the actual costs  
26    associated with the application. Due to the large scope of this proceeding, which will include  
27    amongst other items an in depth review of allocation factors, industrial customer rates and  
28    overall rate structure, FEI is anticipating that this will be a significant proceeding.

29    The types of expenditures and amounts forecast for the duration of the proceeding are provided  
30    in the table below:

---

<sup>35</sup> Exhibit B-1, p. 50.

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1

**Forecast 2017 Rate Design Application Costs, \$ thousands**

Cost Component	2015	2016	2017	Total
<b>Consultant &amp; Contractor Fees</b>	165	445	495	1,105
<b>Legal Fees</b>	50	250	550	850
<b>Commission Costs</b>	25	75	200	300
<b>PACA Reimbursements</b>	10	40	100	150
<b>Other</b>	-	25	75	100
<b>Total</b>	<b>250</b>	<b>835</b>	<b>1,420</b>	<b>2,505</b>

2

3 FEI notes that page 50 of the Application should have stated that the majority of the costs are  
 4 expected to be incurred in 2017 when the majority of the regulatory process is expected to  
 5 occur, and not 2016.

6

7

8

9           25.2   Please provide the total amount spent in application costs on FEI's previous rate  
 10                    design application.

11

12   **Response:**

13   Please refer to the response to BCUC IR 1.23.1.

14

15

16

17           25.3   How much time does FEI anticipate its internal staff will spend on preparation of  
 18                    the rate design application in 2015 and how does this compare, percentage-wise,  
 19                    to the time expected to be spent by consultants?

20

21   **Response:**

22   FEI expects that approximately 5,000 hours of internal staff time will be spent on the preparation  
 23   of the rate design application in 2015, which is approximately ten times greater than the time  
 24   expected to be spent by consultants. In other words, internal employee hours are forecast to  
 25   account for approximately 90 percent of the total time spent and consultant hours are forecast to  
 26   account for approximately 10 percent of the total time spent.

27

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1   **26.0 Reference: DEFERRAL ACCOUNTS**

2                           **Exhibit B-1: Section 7.5.1.3, pp. 51-52**

3                           **New Accounts – 2017 Long-Term Resource Plan (LTRP) Application**

4           FEI states on page 51 of the Application:

5                           It is not possible for FEI to complete the required work for the LTRP as directed  
6                           by the Commission in Order G-189-14 without incurring the incremental  
7                           expenditures that were denied by Order G-138-14.

8                           ...FEI expects to incur \$0.250 million in 2015 and a total of approximately \$1.2  
9                           million on these activities up to the time of filing the 2017 LTRP. Examples of  
10                          these types of costs...are staffing and/or external consulting costs for conducting  
11                          a detailed comparison of end-use forecasting methodologies, staffing and  
12                          consulting costs for end-use forecasting work, consulting costs for developing  
13                          alternative DSM funding and savings scenarios and staffing and/or consulting  
14                          costs for more fully developing infrastructure contingency plans for different  
15                          demand scenarios.<sup>36</sup>

16           In the 2012-2013 FortisBC Energy Utilities (FEU) RRA Decision, the Commission states:

17                          In their evidence, the FEU have outlined work which must be completed but have  
18                          provided no detailed information with respect to the complexity of each directed  
19                          task, the time required to complete the work or any additional cost estimates for  
20                          reports or surveys.

21                          ...Therefore, the Commission Panel does not accept that the need for the \$1.2  
22                          million in 2012 and \$1.5 million in 2013 for this [LTRP] project has been  
23                          adequately supported...It is for these **reasons the Commission Panel will only**  
24                          **approve additional funding in the amount of \$400 thousand in 2012 and**  
25                          **\$600 thousand in 2013 for resource planning...**<sup>37</sup>

26           26.1   Please confirm, or explain otherwise, that FEI's 2013 Base O&M going into the  
27                          PBR included \$400 thousand of the incremental spending approved for the LTRP  
28                          in the 2012-2013 FEU RRA Decision.

29  
30   **Response:**

31   Not Confirmed. The amount included in FEI's Base O&M for the incremental activities that FEI  
32   has been directed to include in the LTRP going into the PBR period is zero.

<sup>36</sup> Exhibit B-1, pp. 51-52.

<sup>37</sup> 2012-2013 FEU RRA Decision, p. 59.



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1 In its statement on page 208 of the FEI PBR Decision, the Commission clarified the amounts  
2 approved for these activities for 2012 and 2013 as follows:

3 *“In the 2012–2013 FEU RRA, the Commission approved an incremental spending*  
4 *amount of \$400,000 in 2012 and a further incremental amount of \$200,000 in 2013*  
5 *related to the Long Term Resource Plan (LTRP).”*

6  
7 Therefore, the total amount of approved O&M in 2013 for incremental LTRP spending was  
8 \$600,000.

9 Then, also in the FEI PBR Decision, the Commission removed this annual amount from Base  
10 O&M as follows:

11 *“...the Panel does not consider it reasonable to approve the incremental spending that*  
12 *was approved in the 2012–2013 FEU RRA Decision. This is because the next LTRP is*  
13 *not expected to be in front of the Commission for another five years. **The Commission***  
14 ***Panel therefore directs FEI to further reduce the Base O&M for the LTRP by***  
15 ***\$600,000.”***

16  
17 Therefore, the amount included in FEI’s Base O&M for the incremental activities that FEI has  
18 been directed to include in the LTRP is zero.

19  
20

21  
22 26.1.1 If confirmed, please provide a detailed explanation of how the \$400  
23 thousand of funding is currently being utilized and why FEI expects to  
24 spend an additional \$250 thousand on the LTRP in 2015. Please  
25 specifically describe what activities the \$250 thousand is expected to be  
26 spent on and what percentage of the spending is expected to be labour  
27 versus non-labour.

28  
29 **Response:**

30 Please refer to the response to BCUC IR 1.26.1.

31  
32

33

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- 1           26.2   Please provide a comparison in tabular form of the 2014 LTRP and the 2017  
2           LTRP which includes the following: (Please note that the information requested  
3           for the 2017 LTRP should be based on FEI's best estimates.)
- 4           • Number of FTEs utilized, both in headcount and in number of hours of time  
5           spent;
  - 6           • Number of consultants utilized and total number of hours of time spent;
  - 7           • Description and number of new initiatives undertaken for the 2014 LTRP  
8           compared to the 2017 LTRP;
  - 9           • Description and number of new Commission directives and recommendations  
10          required to be undertaken by FEI in each of the 2014 and 2017 LTRPs based  
11          on the Commission decisions on the previous LTRPs; and,
  - 12          • Overall complexity of the 2014 LTRP versus the 2017 LTRP, including the  
13          total time spent by FEI from preparation of the application to filing of final and  
14          reply arguments, number of rounds of IRs, and type of hearing process (i.e.  
15          written/oral/NSP/SRP).

16  
17    **Response:**

18    The information available for FEI to respond to this request does not lend itself to the type of  
19    tabular presentation requested. FEI therefore provides the following discussion.

20    FEI does not track the number of hours that all staff from across the company spend on LTRP-  
21    related activity, whether they were for incremental requirements as a result of Commission  
22    directives or not. FEI outsourced substantial analyses, primarily related to end-use demand  
23    forecasting and long term energy efficiency and conservation planning for the 2014 LTRP;  
24    however, FEI has not yet determined how much of the work for the 2017 LTRP will be  
25    outsourced versus being undertaken by FEI employees. Thus FEI cannot state at this time  
26    what its staffing needs versus external consultant activity will be.

27    Table 1 below, as excerpted from BCUC IR 2.68.1 in the FEU 2012-2013 RRA proceeding,  
28    describes the incremental activities that were directed by the Commission and addressed by  
29    FEI for the 2014 LTRP and for which the Commission allowed \$1.0 million (a total of \$400  
30    thousand in 2012 and an incremental \$200 thousand for a total of \$600 thousand in 2013) in  
31    approved rates.

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1 **Table 1: Incremental Activities Directed by the Commission for the 2014 LTRP**

Directive / Initiative	Discussion
<p>20-year vision</p> <ul style="list-style-type: none"> <li>• Macro-economic analysis and scenario development / review</li> <li>• Market transformation scenarios</li> <li>• Contribution to GHG reductions</li> <li>• New technology forecasting</li> <li>• Impact on BC Energy Objectives</li> <li>• Drivers for non-EEC/infrastructure resource requirements</li> </ul>	<p><i>These activities are required by Commission directive no. 1. Sub-bullets in left hand column describe FEU's understanding of scope of this directive.</i></p>
<p>New Stakeholder Consultation Initiatives</p> <ul style="list-style-type: none"> <li>• Resource Planning Advisory Group, Community Consultation Activities and other new consultation activities.</li> </ul>	<p><i>This item is not specifically listed in the Commission directives; however, FEU committed to setup a Resource Plan Advisory Group during the proceeding. The Commission Panel commented as follows:</i></p> <p><i>"With respect to stakeholder input, the Panel is most encouraged by Terasen's intention to establish a Resource Plan Advisory Group as it may provide a sounding board and assist in the preparation of future plans." (p. 13)</i></p> <p><i>"The Panel believes that these recommendations along with the stated intention of Terasen Utilities to setup a Resource Plan Advisory Group will be helpful in promoting further development of the long term planning process." (p. 19)</i></p> <p><i>Increased consultation activities are a necessary part of the additional scenario setting, analyses and review of outcomes needed to improve the LTRP. The need to consult with stakeholders is apparent throughout the Commission decision report and is highlighted by the discussion of intervenor submissions in the preamble to the directive.</i></p>
<p>EEC Planning and Impacts of New Initiatives:</p> <ul style="list-style-type: none"> <li>• GHG impact modelling and analysis</li> <li>• Improved analysis of long term EEC planning and scenarios</li> <li>• Impact of new service initiatives on EEC scenarios, resource requirements, demand and emissions</li> </ul>	<p><i>These activities are required by Commission directive no. 2. Sub-bullets in left hand column describe FEU's understanding of scope of this directive.</i></p>

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Directive / Initiative	Discussion
Planning Environment and Demand Forecasting <ul style="list-style-type: none"> <li>• Develop end-use forecasting methodology</li> <li>• Compare with traditional methodology and prove out new methodology pros and cons</li> <li>• Broader consideration of economic inputs to and impacts of planning scenarios</li> <li>• Incorporate potential legislative, regulatory or market transformational changes into forecast and resource assessment</li> <li>• Rigorous analysis of scenarios that consider the impact of new service initiatives on resource needs, energy demand and GHG emissions</li> <li>• Consideration of other variables that could impact scenarios and results</li> <li>• Regional / provincial thermal energy demand investigations</li> <li>• Regional / provincial transportation energy demand investigations</li> </ul>	<i>These activities are required by Commission directive no. 3. Sub-bullets in left hand column describe FEU's understanding of scope of this directive.</i>

1

2 FEI interprets Commission Order G-189-14 as requiring that all of the above incremental items

3 from the 2014 LTRP must again be addressed in preparing the 2017 LTRP. In addition to the

4 incremental items listed above, the Commission has directed FEI to complete the activities

5 listed In Table 2 for the 2017 LTRP:

6 **Table 2: Incremental Activities Added to Those in Table 1 by the Commission for the 2017 LTRP**

Directive / Initiative	Discussion
The Commission Panel directs the FEU, to: <ul style="list-style-type: none"> <li>• in its next LTRP filing, provide a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods; and</li> <li>• continue use of the Traditional Method as a parallel approach until such time as the Commission approves a new end-use method as a substitute</li> </ul>	Given that a detailed review of the reason for adopting the new end-use approach was carried out during the 2014 LTRP review process, FEI interprets the first bullet in this item to require a more extensive review of a wide range of potential models. FEI is considering outsourcing this activity.  The second bullet in this item identifies carrying over an activity from the 2014 LTRP that FEI had intended to stop carrying out.

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Directive / Initiative	Discussion
<p>The Panel therefore directs the FEU to include, in its next LTRP, the following information:</p> <ul style="list-style-type: none"> <li>• The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;</li> <li>• Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low-income, commercial etc.), including:               <ul style="list-style-type: none"> <li>○ Total Resource Cost/modified Total Resource Cost test results;</li> <li>○ Utility Cost Test result, expressed as a ratio and \$/GJ;</li> <li>○ Delivery rate impact;</li> <li>○ Estimated total bill impact (including delivery and commodity), \$ and %, with residential split between high and low use gas customers; and</li> <li>○ Estimated gas (GJ) and GHG emission reductions.</li> </ul> </li> </ul>	<p>Analysis completed for the 2014 LTRP will need to be conducted again in order to provide this information, but the majority of this list represents analysis and reporting that are incremental to the activities conducted for the 2014 LTRP.</p>
<p>Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments.</p>	<p>Although this issue has been discussed and addressed in the 2014 LTRP, FEI interprets this directive to require further examination of potential peak capacity avoidance potential of EEC activity then has been completed before or is common for gas utilities.</p>
<p>To ensure regulatory efficiency in the review of CPCN applications, the Panel directs that the FEU include in their next LTRP, a contingency plan(s) that outlines the impact(s) to FEU's System Resource Needs and Alternatives based on potential changes in supply, demand, market conditions and significant new developments in the industry that were not identified in the LTRP as being associated with the Reference Case or most-likely forecast.</p>	<p>FEI interprets this directive to be incremental activity to that of the 2014 LTRP.</p>
<p>The Panel therefore directs FEU to include in the next LTRP a description of its long term vision for price risk management and provides broad principles which can be used to inform the PRMP.</p>	<p>FEI interprets this directive to be incremental activity to that of the 2014 LTRP.</p>

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1 Table 3 provides a comparison of costs approved for 2012 and 2013 to prepare the 2014 LTRP  
 2 to what is proposed in 2014 through 2016 to prepare the 2017 LTRP and the method of  
 3 recovery of those costs.

4 **Table 3: Comparison of LTRP Related Costs**

	2012 – 2013 Approved for the LTRP Incremental Activities	2014 – 2017 Approved for the LTRP Incremental Activities	2014-2017 Deferral Account for LTRP Incremental Activities (estimated)
<b>Year 1</b>	\$400,000	\$0	\$250,000
<b>Year 2</b>	\$600,000	\$0	\$600,000
<b>Year 3</b>	--	\$0	\$350,000
<b>Total</b>	\$1.0 million	\$0	\$1.2 million

5  
 6 FEI considers a number of the incremental activities to be more complex than those conducted  
 7 for the 2014 LTRP.

8 FEI's estimated funding on an annual basis to complete the 2017 LTRP is consistent with the  
 9 level of funding for the 2014 LTRP when considering the additional activities that it has been  
 10 directed to complete for the 2017 iteration. FEI is seeking approval of a deferral account to  
 11 capture these incremental costs of preparing the 2017 LTRP, and only actual costs incurred will  
 12 be recorded in the account.

13  
 14

15  
 16 26.3 Will FEI be hiring additional staff to participate in the LTRP work? If yes, please  
 17 provide the number of staff expected to be hired and a description of their roles.

18  
 19 **Response:**

20 Please refer to the response to BCUC IR 1.26.2.

21  
 22

23  
 24 26.4 Given that the Commission in the 2012-2013 FEU RRA Decision only approved a  
 25 total of \$1 million for the 2014 LTRP, please explain why it is appropriate for FEI  
 26 to spend \$1.6 million on the 2017 LTRP (\$1.2 million stated in the Application  
 27 plus \$400 thousand already included in the PBR Base O&M).

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1

2 **Response:**

3 As discussed in the response to BCUC IR 1.26.1 and 1.26.2, FEI is estimating to spend up to  
4 \$1.2 million in total over the three-years 2015 to 2017, not \$1.6 million. The assumption that  
5 there is currently \$400 thousand in the PBR O&M base for these activities is incorrect. As  
6 discussed in response to BCUC IR 1.26.2, the estimated amount is consistent with the costs of  
7 \$1.0 million that the Commission approved for the completion of the 2014 LTRP given that the  
8 Commission has directed FEI to undertake additional activity to that which was required for the  
9 2014 LTRP.

10

11

12

13 26.5 Please provide a detailed breakdown of the estimated \$1.2 million cost to be  
14 spent on the LTRP and include the following information:

15 • Detailed description of each cost item identified, including the year each cost  
16 item is expected to be incurred (if more than one year, indicate how much is  
17 expected to be spent in each year);

18 • Whether or not each cost item should be characterized as “routine” or  
19 “recurring”, or if the cost should be characterized as “incremental” or  
20 “extraordinary”;

21 • In the case of costs identified as extraordinary/incremental, please explain  
22 whether these costs are related to Commission directives from the 2014  
23 LTRP Decision or whether the costs are the result of a FEI-driven  
24 initiative/innovation. For costs which are identified as being the result of the  
25 2014 LTRP Decision, please specifically reference the applicable directive  
26 and the action FEI is taking to comply with each directive.

27

28 **Response:**

29 FEI does not currently have the detailed cost breakdown requested by the Commission for the  
30 reasons discussed in the response to BCUC IR 1.26.2.

31 FEI is unclear about the definitions that the Commission is ascribing to the terms “routine” and  
32 “extraordinary” in this request, but considers all activities related to the LTRP for which it is  
33 requesting deferral account treatment to be incremental activities related to Commission  
34 directives. Please see the response to BCUC IR 1.26.2 for a list of activities that are  
35 incremental for the 2014 LTRP as a result of Commission directives, and those that are further  
36 incremental activities for the 2017 LTRP as a result of further Commission directives.



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1 FEI believes that many of the incremental activities directed by the Commission for the 2014  
2 LTRP and additional incremental activities directed by the Commission for the 2017 LTRP could  
3 be recurring activities. However, the conflict between Commission Order G-138-14, in which  
4 the Commission stated they did not expect to see another LTRP for 5 years, thus reducing costs  
5 allowed in O&M by \$600 thousand annually, and G-189-14 in which the Commission directs FEI  
6 to complete the next LTRP in 2.5 years including substantial incremental analyses, leaves it  
7 unclear as to the expectations for integrated resource planning beyond 2017. As such, FEI  
8 cannot state at this time if such activities are recurring. This conflict in directives makes it  
9 challenging to maintain continuity in conducting these activities and to improve the LTRP  
10 process and plan.

11

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1    **27.0 Reference: DEFERRAL ACCOUNTS**

2                                    **Exhibit B-1-1: Section 11, Schedule 30**

3                                    **2015-2019 Annual Review Costs Deferral Account**

4                    Schedule 30 in Section 11 shows a gross addition for 2015 of \$275 thousand to the  
 5                    2015-2019 Annual Review Costs deferral account.<sup>38</sup>

6                    27.1 Please provide a detailed breakdown and description of the estimated \$275  
 7                    thousand expenditure for the 2015 Annual Review. As part of the breakdown,  
 8                    please clearly distinguish between pre-application filing costs and post-  
 9                    application filing costs.

10

11    **Response:**

12                    The breakdown of the forecast costs of \$275 thousand includes forecasts of costs for the  
 13                    Commission’s direct costs, Intervener Participant Assistance Cost Awards (PACA), legal fees  
 14                    and administrative costs (including disbursements such as courier and direct office supplies).  
 15                    Regardless of the amount of costs FEI has forecast, only the actual costs incurred will be  
 16                    recorded in the Annual Review Costs deferral account. Four separate processes will occur in  
 17                    2015, identified as follows:

Regulatory Review Costs	Estimated Amount
Annual Review of 2015 Rates	\$ 60,000
Annual Review of 2016 Rates	60,000
Service Quality Indicator Threshold Consultation Process*	25,000
Depreciation Study	110,000
Administrative Costs	20,000
	<b>\$275,000</b>

18                    \* Relates to both FEI and FBC, this amount represents FEI 50 percent portion

19  
 20                    FEI has little to no control of the actual final costs as those amounts will be directly influenced  
 21                    by the regulatory review process determined by the Commission.

22                    The regulatory review costs in the table above are divided between pre-application filing costs  
 23                    and post application filing costs as follows:

- 24                    • The bulk of the costs of the Annual Review processes are incurred post-application, with  
 25                    only a portion of legal fees incurred pre-application.

<sup>38</sup> Exhibit B-1-1, Section 11, Schedule 30.



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- 1       • Both the service quality indicator threshold consultation process and the depreciation  
2       study costs would be incurred pre-application.
- 3       • Administrative costs would be primarily incurred post application.

4  
5

6

7       27.2   Please provide the amount of application costs incurred as of the date of filing  
8       the responses to these IRs and provide a description and breakdown of these  
9       expenditures.

10

11    **Response:**

12    The actual application costs recorded in the deferral account as of the date of filing the  
13    responses to these IRs is approximately \$25 thousand. Of the \$25 thousand, approximately \$16  
14    thousand relates to legal fees and \$9 thousand relates to the SQI Consultation process for  
15    some of the participant cost claims and use of the hearing room.

16



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1 **28.0 Reference: DEFERRAL ACCOUNTS**

2 **Exhibit B-1: Section 7.5.2.1, pp. 52-53; Exhibit B-1-1, Section 11,**  
 3 **Schedules 29 and 30**

4 **Changes to Deferral Accounts – BFI Costs and Recoveries**

5 28.1 Please separately provide the projected/actual ending 2014 and forecast ending  
 6 2015 balances for each of the “BFI Costs and Recoveries Account” and the “BFI  
 7 Costs and Recoveries Account – All Other Recoveries”.

8  
 9 **Response:**

10 The balance of the account at the end of 2014 and 2015 broken down into these two  
 11 components is displayed in the following table. FEI has not forecast excess station recoveries;  
 12 therefore, there are no additions to this account forecast in 2015.

\$000	2014	2015
BFI Cost & Recoveries Account	\$ (46)	\$ (46)
BFI Cost & Recoveries Account - All Other Recoveries	(55)	(55)
<b>Total</b>	<b>\$ (100)</b>	<b>\$ (100)</b>

13

14

15

16

17 28.2 Please explain why FEI is requesting to transfer the BFI Costs and Recoveries  
 18 Account – All Other Recoveries to the CNG and LNG Recoveries deferral  
 19 account at the end of 2015, as opposed to making the transfer effective January  
 20 1, 2015.

21

22 **Response:**

23 FEI is open to transferring the account effective January 1, 2015. At the time of filing, primarily  
 24 due to the complexity and history of the NGT program and Decisions, FEI thought it was  
 25 appropriate to transfer the balance and amortize it into rates subsequent to receiving approval  
 26 to do so.

27

28

29



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1           28.3   Please indicate which deferral account category the remaining BFI Costs and  
2                   Recoveries deferral account will be recorded under within FEI's financial  
3                   schedules.

4

5    **Response:**

6    FEI would continue to categorize the remaining BFI Costs and Recoveries deferral account as a  
7    Residual Deferral Account.

8

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1 **G. EARNINGS SHARING**

2 **29.0 Reference: EARNINGS SHARING RATE RIDER**

3 **Exhibit B-1: Section 10, p. 65**

4 **Earnings sharing rate rider and deferral account**

5 FEI states that it: “proposes to distribute \$3.341 million to customers in 2015 via a rate  
6 rider. This rider treatment is consistent with that used in FEI’s 2004 PBR Plan, and,  
7 given the amalgamation, is the only method available to stream the 2014 earnings  
8 sharing to customers in the Mainland region.”<sup>39</sup>

9 29.1 Please clarify what amortization period FEI is requesting to be applied to the  
10 earnings sharing rate rider.

11  
12 **Response:**

13 FEI is returning the earnings sharing as a rate rider, and not amortizing it. This is because the  
14 rate rider is to be streamed only to Mainland customers. The rate rider would be effective for a  
15 twelve month period, from January 1, 2015.

16  
17

18  
19 29.2 With regards to the remainder of the PBR term (i.e. 2015-2019), is the use of a  
20 rate rider the only mechanism available to distribute the earnings sharing to  
21 customers, or are other methods available, such as amortization of earnings  
22 sharing through a deferral account? Please discuss.

23  
24 **Response:**

25 With regards to the remainder of the PBR term, the use of a rate rider is not the only mechanism  
26 available to distribute earnings sharing to customers. As noted in the question, to the extent  
27 that the earnings sharing amount is applicable to all customers, the earnings sharing may also  
28 be amortized into delivery rates.

29 The 2014 earnings sharing amount only applies to the Mainland region and as such, the rate  
30 rider method is the only way to stream the 2014 sharing amount to Mainland customers. Since  
31 the 2015 sharing amount will be applicable to all customers, FEI will evaluate the merits of both  
32 methods and propose an approach in the Annual Review to set 2016 delivery rates.

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<sup>39</sup> Exhibit B-1, Section 10, p. 65.



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Directive 5 of Commission Order G-162-14 states:

FortisBC Energy Inc. is approved to establish the Earnings Sharing deferral account to flow through to customers any result of the Earnings Sharing Mechanism. FortisBC Energy Inc. shall apply a one year amortization period to the Earnings Sharing deferral account and shall accrue carrying charges on the deferral account based on FortisBC Energy Inc.'s currently approved weighted average cost of capital.

29.3 Please explain if FEI is proposing to use the requested earnings sharing rate rider instead of the previously approved earnings sharing deferral account, or if FEI is proposing to utilize both mechanisms.

**Response:**

This response also addresses BCUC IR 1.29.3.1 and 1.29.3.2.

FEI is not proposing any change to the Earnings Sharing deferral account approved in Order G-162-14. It is the method of distributing the 2014 balance in the Earnings Sharing deferral account that is the subject of FEI's proposal. More specifically, the earnings sharing rate rider is the method that will be used to distribute the 2014 balance in the Earnings Sharing deferral account that was approved by Order G-162-14. As such, the deferral account is still required to capture amounts owing to or from customers and should not be discontinued. Furthermore, with the use of the rate rider in 2014, the account will also capture any demand related variances in 2014 amounts distributed.

As explained in the Application and in the response to BCUC IR 1.29.2, the 2014 earnings sharing amount is only applicable to the Mainland Region and the disposition of the balance in this account through the use of a rate rider is the only way to stream this 2014 amount to Mainland customers.

29.3.1 If FEI is proposing to utilize both, please explain what separate purpose(s) the rate rider and deferral account serve, including an explanation for why both mechanisms are necessary.



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1 **Response:**

2 Please refer to the response to BCUC IR 1.29.3.

3  
4

5

6 29.3.2 If FEI is proposing to utilize the rate rider instead of the deferral  
7 account, please discuss whether it would be more appropriate for this  
8 deferral account to be discontinued.

9

10 **Response:**

11 Please refer to the response to BCUC IR 1.29.3.

12

13

14

15 29.4 Notwithstanding the need to use the rate rider to stream the 2014 earnings  
16 sharing to customers in the Mainland, please discuss the differences, if any,  
17 between using a rate rider and using a deferral account to capture and distribute  
18 earnings sharing to customers. Please include in the discussion the difference or  
19 impact of using the two mechanisms from both FEI's perspective (i.e. in terms of  
20 recording and reporting differences, etc.) and from the ratepayers' perspective  
21 (i.e. in terms of bill presentation, amount, etc.).

22

23 **Response:**

24 As discussed in the response to BCUC IR 1.29.3, the deferral account is required regardless of  
25 the method used to distribute the earnings sharing amount. The differences between using a  
26 rate rider and amortization expense to distribute the earnings sharing amount captured in the  
27 deferral account are minimal with the overall benefit of the rate rider approach being that it can  
28 be used when a balance needs to be streamed to a particular group of customers or when the  
29 visibility of an amount is necessary.

30 From FEI's perspective, the rate rider approach may result in cash flow variances for the  
31 Company and may result in a residual balance remaining in the deferral account at the end of  
32 2015 because of the volumetric nature of the calculation; however, the two approaches result in  
33 the balance of the account ultimately being refunded to or recovered from customers.



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1 From the perspective of a customer, since both approaches are embedded in the overall  
2 delivery charge, customers do not see any differences in the presentation of their monthly bill.  
3 In the case of earnings sharing, the two approaches are not expected to have a material impact  
4 on the amount allocated to each customer group (i.e. rate schedule). This is because delivery  
5 margin is used as the basis for allocation of the rate rider and this aligns with the treatment of  
6 revenue surpluses or deficiencies (in which the amortization expense will be captured) on  
7 delivery rates.

8

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1 **H. ACCOUNTING MATTERS AND EXOGENOUS FACTORS**

2 **30.0 Reference: NON-RATE BASE DEFERRAL ACCOUNTS**

3 **Exhibit B-1: pp. 107-110**

4 **EEC Incentives for AES/TES**

5 The following excerpt is from the FEU 2012-2013 RRA Decision:

6 In 2010 and 2011, the FEU participated in the Public Sector Energy Conservation  
 7 Agreement (PSECA) program with BC Hydro and SolarBC. The PSECA Initiative  
 8 was operated by the provincial Climate Action Secretariat (CAS). Under the  
 9 PSECA Initiative, the CAS reviewed and approved applications for incentive  
 10 funding for public sector organizations to reduce energy consumption and GHG  
 11 emissions...

12 In 2011, the FEU project to spend \$324,430 on the PSECA program for three  
 13 school districts (SD): SD 72 Campbell River; SD 71 Comox Valley; SD 37  
 14 Delta.....Approximately \$116 thousand in incentive payment was committed to  
 15 Delta SD...<sup>40</sup>

16 In Table 12-1 of the Application, FEI identifies the following projects of which EEC  
 17 Incentives were provided<sup>41</sup>:

**Table 12-1: EEC Incentives for AES/TES (\$ millions)**

<u>FAES Project</u>	<u>Incentive Description</u>	<u>Amount</u>
Delta School District	High Efficiency Boilers	0.116
Glen Valley	Tankless Water Heaters (2012)	0.019
Glen Valley	Tankless Water Heaters (2013)	0.013
Helen Gorman	Ground Source Heat Pump	0.100
<b>Total</b>		<u>0.248</u>

18

19 30.1 The \$324,430 incentive funding for the 3 schools (originally projected in 2011)  
 20 are different than the projects identified in Table 12-1 of the Application. Please  
 21 confirm, or explain otherwise, that the Glen Valley and Helen Gorman projects  
 22 are “public sector” projects.  
 23

24 **Response:**

25 In the excerpt above, the Companies state that in 2011, the FEU projected to spend \$324,430 in  
 26 2011 on 3 school districts (emphasis added), not 3 schools as stated in the Information  
 27 Request. The excerpt from the FEU 2012-2013 relates to the Public Sector Energy

<sup>40</sup> FEU 2012-2013 RRA Decision, pp. 180-181.

<sup>41</sup> Exhibit B-1, p. 108.



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1 Conservation Agreement program, which was a specific program operated by the province  
2 aimed at reducing energy consumption and GHG emissions in public sector buildings. The  
3 Glen Valley and Helen Gorman projects were not part of the province's Public Sector Energy  
4 Conservation Agreement program. These two projects are described in the responses to BCUC  
5 IR 1.30.2 and 1.30.3, respectively.

6  
7

8  
9 30.2 Please briefly describe the Glen Valley project and the technology (gas-fired  
10 water heater?) that is designed to reduce natural gas consumption.

11  
12 **Response:**

13 Glen Valley is a new construction project in the Central Okanagan. The project received  
14 incentives for installing condensing tankless water heaters which have a minimum energy factor  
15 of 0.92. By contrast, the minimum efficiency performance standard for water heaters in British  
16 Columbia currently ranges from 0.56 – 0.64 energy factor<sup>42</sup>. Thus, the efficiency of the water  
17 heaters at Glen Valley for which incentives were provided is significantly higher than the  
18 minimum efficiency level currently available in British Columbia. Higher efficiency equipment  
19 results in reduced gas consumption.

20 Although unrelated to the incentives provided by FEI, Glen Valley also has a geo-exchange  
21 heating system and the ground source loops for this system are owned by FAES. The  
22 incentives provided by FEI for installing condensing tankless water heaters are not related to the  
23 geo-exchange system.

24  
25

26  
27 30.3 Please briefly describe the Helen Gorman project and how the ground source  
28 heat pump is designed to reduce natural gas consumption.

29  
30 **Response:**

31 Helen Gorman is an elementary school in the Central Okanagan. This project consisted of a  
32 retrofit of an existing natural gas boiler-fired heating plant with a geo-exchange, or ground  
33 source heat pump system. The following is an excerpt from the website of GeoExchangeBC, an  
34 industry group: "A 'ground source heat pump', also known as a 'geoexchange system,' uses the

<sup>42</sup> Source: <http://www.empr.gov.bc.ca/EEC/Strategy/EEA/Pages/RegulatedProducts.aspx>.

FortisBC Energy Inc. (FEI or the Company) Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan (the PBR Plan) approved for 2014 through 2019 by Order G-139-14 (the Application)	Submission Date: March 2, 2015
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1 ground's stable year-round temperature to more efficiently heat or cool your home.”<sup>43</sup> In a geo-  
2 exchange or ground source heat pump system, the energy available in the ground displaces a  
3 portion of the natural gas used to meet the thermal demand of a building. As indicated on page  
4 2 of Undertaking 44 (Ex. B-77) in the FEU's 2012-2013 Revenue Requirements proceeding,  
5 provided as Attachment 30.3, the reduction in consumption of natural gas for Helen Gorman  
6 School (shown as School District 23 in Attachment 30.3) was estimated to be 1,400 GJ/year.  
7 FEI notes that Helen Gorman school owns all of the mechanical equipment for the geo-  
8 exchange system, while FAES owns the ground source loops in the geo-exchange system.

9  
10

11  
12 FEI states that: “[i]n the 2014 PBR Application, FEI indicated it would continue  
13 accumulating EEC incentive costs relating to AES/TES activities in this deferral  
14 account.”<sup>44</sup>

15 30.4 Does FEI intend to continue accruals to this deferral account during the PBR  
16 term?

17  
18

**Response:**

19 No. Page 110 of the Annual Review Application (Ex. B-1) states: “...FEI proposes to transfer  
20 the 2014 ending balance in the account to the rate base EEC deferral account effective January  
21 1, 2015, which will result in these incentives being amortized into rates over 10 years. Once this  
22 transfer occurs, FEI will discontinue the use of the EEC Incentives for AES/TES deferral  
23 account effective January 1, 2015 and capture any future EEC incentives related to AES  
24 customers, regardless of thermal energy supplier, within the existing approved EEC funding  
25 envelope.”

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30 In the Application, FEI proposes: “to transfer the 2014 ending balance in the [EEC  
31 Incentives for AES/TES deferral] account to the rate base EEC deferral account effective

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<sup>43</sup> Source: <http://www.geoexchangebc.com/tutorial.php>

<sup>44</sup> Ibid.



FortisBC Energy Inc. (FEI or the Company) Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan (the PBR Plan) approved for 2014 through 2019 by Order G-139-14 (the Application)	Submission Date: March 2, 2015
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1 January 1, 2015, which will result in these incentives being amortized into rates over 10  
 2 years.<sup>45</sup>

3 30.5 As an alternative to amortizing the proposed balance of this deferral account over  
 4 10 years, please provide the rate impact if FEI were directed to:

- 5 (i) Expense the full amount in the current year;
- 6 (ii) Amortize the deferred amounts over 2 years.

7  
 8 **Response:**

9 The approximate rate impacts for the proposed and alternative amortization scenarios provided  
 10 above are included in the table below. However, FEI notes that adopting a different amortization  
 11 period than 10 years would require this deferral account to remain separate from the existing  
 12 rate base EEC deferral account which is currently amortized over 10 years.

13 FEI has provided the impact of a one-year amortization period in 2015, rather than expensing  
 14 the amount through O&M because expensing the amount through O&M is not feasible given  
 15 that the amount is not embedded within the formula O&M for 2015. In any case, the revenue  
 16 requirement impact is generally the same between the two alternatives.

Amortization	2015 Revenue Requirement Impact (\$000s)	2015 Delivery Rate Impact %
<b>10 year</b>	\$39	0.01%
<b>1 year</b>	\$258	0.03%
<b>2 year</b>	\$136	0.02%

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 21 On pages 108 and 109 of the Application, FEI states that the TES projects are operated  
 22 and undertaken by FAES, not FEI.

23 30.6 Should the balance in the EEC Incentives for AES/TES deferral account be  
 24 included in FAES' TESDA? Why or why not?  
 25

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<sup>45</sup> Exhibit B-1, p. 110.

FortisBC Energy Inc. (FEI or the Company) Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan (the PBR Plan) approved for 2014 through 2019 by Order G-139-14 (the Application)	Submission Date: March 2, 2015
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1 **Response:**

2 No, the balance in the EEC Incentives for AES/TES deferral account should not be included in  
3 FAES/TESDA. There are three main reasons for this as explained below.

4 First, FEI has a right to a reasonable opportunity to recover the balance in the EEC Incentives  
5 for AES/TES deferral account in its rates. As discussed on pages 108-109 of the Application,  
6 the balance in this account consists of FEI's expenditures on demand-side measures made in  
7 accordance with an expenditure schedule accepted by the Commission under section 44.2(1)(a)  
8 of the Utilities Commission Act. Pursuant to section 60(1)(b)(i) of the Utilities Commission Act,  
9 the Commission must have due regard to setting a rate that "provides to the public utility for  
10 which the rate is set a fair and reasonable return on any expenditure made by it to reduce  
11 energy demands." Since the balance in the EEC Incentives AES/TES deferral account were  
12 expenditures made to reduce energy demands, FEI's rates must be set to recover the  
13 expenditures in the EEC Incentives for AES/TES deferral account in order to comply with  
14 section 60(1)(b)(i).

15 Second, transferring the balance in the EEC Incentives AES/TES deferral account to the FAES  
16 TESDA would require FAES's customer to pay back the incentive to FAES. The incentive was  
17 provided by FEI to the FAES customer to provide an incentive to adopt energy efficient  
18 technology. If FAES is then required to recover the same amount from the customer when it  
19 recovers the balance in the AES/TES deferral account, the customer would then have to repay  
20 the amount which the customer believed was an incentive payment that it would not have to pay  
21 back. This would be unfair to the customer and contrary to the intent of providing the incentive.

22 Third, since FAES did not make the EEC expenditure, FAES would recover amounts that it had  
23 never expended. The end result would be to reduce FAES's costs, rather than the FAES  
24 customer's costs. This would be a windfall to FAES and again contrary to the intent of the  
25 incentive which was to provide an incentive to the customer to adopt energy efficient  
26 technology.

27 In summary, the balance in the EEC Incentives for AES/TES deferral account should not be  
28 included in FAES/TESDA because (1) FEI would not be provided its right to a reasonable  
29 opportunity to recover its expenditures made to reduce energy demands, (2) the customer to  
30 whom the incentive was provided would have to repay that incentive amount, which would be  
31 unfair to the customer and contrary to the intent of providing the incentive, and (3) would unfairly  
32 benefit FAES which would recover the incentive amount in its rates even though it never made  
33 the expenditure.

34



FortisBC Energy Inc. (FEI or the Company) Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan (the PBR Plan) approved for 2014 through 2019 by Order G-139-14 (the Application)	Submission Date: March 2, 2015
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1 **I. SERVICE QUALITY INDICATORS**

2 **31.0 Reference: Transmission Reportable Incidents**

3 **Exhibit B-1-1: Section 13, p. 123**

4 **Oil & Gas Commission (OGC) Criteria**

5 FEI states on page 123 of the Application:

6 In the past, the practice has been to report only on the higher pressure  
7 transmission events designated as serious. However, the OGC has new  
8 reporting criteria effective October 1, 2014, which require the Company to report  
9 on more incidents and events.<sup>46</sup>

10 31.1 Please provide a copy of the new OGC reporting criteria.

11

12 **Response:**

13 Attachment 31.1 includes the May 30, 2014 OGC Bulletin entitled “New Online Minor Incident  
14 Reporting and Training”, the new Incident Reporting Guidelines and new Incident Classification  
15 Matrix.

16

17

18

19 31.2 Please provide a side-by-side comparison of the past reporting practice with the  
20 new OGC reporting criteria.

21

22 **Response:**

23 The amount of pipeline subject to the new OGC reporting requirements has increased  
24 approximately 25 percent as a result of including intermediate pressure pipelines. In addition,  
25 the severity threshold for reporting incidents has been lowered. A side-by-side comparison of  
26 the past and new reporting criteria is as follows:

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<sup>46</sup> Exhibit B-1-1, p. 123.



FortisBC Energy Inc. (FEI or the Company) Application for Approval of 2015 Delivery Rates pursuant to the Multi-Year Performance Based Ratemaking Plan (the PBR Plan) approved for 2014 through 2019 by Order G-139-14 (the Application)	Submission Date: March 2, 2015
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	Past Reporting Criteria	New Reporting Criteria
Severity Threshold	1. Critical incidents 2. Serious incidents	1. Serious (Level 3) incidents - corresponds to critical incidents under old criteria. 2. Major (Level 2) incidents - corresponds to serious incidents under old criteria. 3. Moderate (Level 1) incidents 4. Minor incidents <sup>1</sup>
Pressure Threshold	Applied to only to higher pressure transmission assets greater than 300psi.	Applies to both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi.

1 <sup>1</sup> FEI notes that minor incidents are reported to the OGC through an online submission and include incidents such as unauthorized excavations around a pipeline resulting in damage to coating or vehicle entering facility compound with no or minor damage to equipment or piping (no leak). FEI has therefore determined that it is more reasonable not to include minor incidents in the Transmission Reportable Incidents informational SQI.

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31.3 Please provide more details on how FEI's reporting will change under the new reporting criteria and please explain why the change will limit the comparability of historical performance data for this metric.

**Response:**

The reporting criteria changed as of October 1, 2014 so that FEI is now reporting more incidents to the OGC as described in the Application, p. 123, and the response to BCUC IR 1.31.2. The impact of this change limits the comparability of the historical performance data for this SQI because there will be more incidents included in the Transmission Reportable Incidents informational SQI than in the past due to the increase in the scope of incidents that are now required to be reported by the OGC.



## **Attachment 5.1**

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### **REFER TO LIVE SPREADSHEET MODEL**

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

## **Attachment 5.1.1**

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### **REFER TO LIVE SPREADSHEET MODEL**

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

## **Attachment 6.2**

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### **REFER TO LIVE SPREADSHEET MODELS**

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

## **Attachment 7.3**

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**REFER TO LIVE SPREADSHEET MODEL**

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

## **Attachment 7.4**

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### **REFER TO LIVE SPREADSHEET MODEL**

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

**Attachment 30.3**

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**FortisBC Energy Utilities ("FEU")**  
**2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION**

**UNDERTAKING No. 44**

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**HEARING DATE:** November 15, 2011

**TRANSCRIPT**

**REFERENCE:** Volume 9, Page 1410, Lines 9 to 17; Page 1411, Lines 10 to 14;  
Page 1412, Lines 2 to 12

**REQUESTOR:** Mr. Fulton

**WITNESS:** Ms. Smith

**QUESTION:** Provide the specific measures and the projected associated savings the PSECA incentives funded for the Ministry of Citizen Services, School District 72 (Campbell River), and School District 23 (Central Okanagan).

---

**RESPONSE:**

Both the Real Estate Portfolio Management (Ministry of Labour, Citizen's Services and Open Government) and School District 72 were PSECA Initiative participants, and received funding commitments via that program. Please refer to the following table for the requested details:

Approved Energy Saving Measures	Expected Annual Natural Gas Savings (GJ/yr)
<b>Real Estate Portfolio Management (Ministry of Labour, Citizen's Services and Open Government)</b>	
1 High Efficiency Boilers, blocks A and C	2,227
2 High Efficiency Domestic Water Heaters Block A	114
3 High Efficiency Domestic Water Heaters Block B & C	363
4 High Efficiency Domestic Water Heaters Block D	249
5 Domestic Water Heater Scheduling	40
6 Reduction of Kitchen Make-Up Air Unit Run Time	401
<b>TOTAL</b>	<b>3,394</b>
<b>School District #72 (Campbell River)</b>	
1 High Efficiency Boiler	1,510
2 Heat Pump Chiller	3,812
<b>TOTAL</b>	<b>5,322</b>

**FortisBC Energy Utilities (“FEU”)  
2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION**

**UNDERTAKING No. 44**

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For clarity, School District 23 (Central Okanagan) is not a PSECA program participant, but is instead being provided an EEC incentive for participating in a small scale pilot study. The requested details are provided in the following table:

<b>Energy Saving Measure</b>	<b>Expected Annual Natural Gas Savings (GJ/yr)</b>
Geoexchange HVAC System	1,400

**Attachment 31.1**

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# INDUSTRY BULLETIN

## 2014-03

Updated May 30, 2014



### New Online Minor Incident Reporting and Training

The BC Oil and Gas Commission (Commission) has implemented an Online Minor Incident Reporting System as an improved process for permit holders to report minor incidents. The system, operated through the Commission's Knowledge, Enterprise, Resource, Management, Information and Technology (KERMIT) platform, requires permit holders' KERMIT administrators to assign personnel with the necessary authorization to submit the report (instructions can be found in the [Online Minor Incident Reporting System User Guide](#)).

Minor incidents – which do not meet Commission Level 1, 2 or 3 classifications and have a risk score of two or less – must be entered into the Online Minor Incident Reporting System within 24 hours. If the minor incident involves a reportable spill or leak, the permit holder must also call Emergency Management B.C. If the minor incident involves a pipeline, a Permit Holder Post Incident Report must be submitted to the Commission within 60 days.

Permit holders can start entering minor incidents online anytime after March 27. On Oct. 1, 2014 online reporting for minor incidents will become mandatory. This date has been selected to allow for continued development of the KERMIT online supporting module. Companies that have been using the online reporting tool are encouraged to continue.

The system is part of the new [Emergency Management Regulation](#), which becomes effective Oct. 1, 2014. Also developed with the regulation are a new [Incident Classification Matrix](#), [Incident Reporting Guidelines](#), and [Form A – Minor Incident Notification Form](#). Permit holders are asked to incorporate the new documents into their Emergency Response Plans and train personnel by Oct. 1, 2014.

The Commission will be hosting training on the Online Minor Incident Reporting System in the following cities. Due to space limitations please limit attendees to two per company. Each venue will have two sessions starting at 9:30 a.m. and 1:30 p.m. Attendees are asked to RSVP for one of the sessions by Mar. 27 at [EMP@bcogc.ca](mailto:EMP@bcogc.ca).

- Fort St. John, BC Oil and Gas Commission office – March 31.
- Calgary, Palliser Hotel – April 3.

For further information on this industry bulletin please contact:

Heidi Elias-Bertrim  
Emergency Response Coordinator  
BC Oil and Gas Commission  
[EMP@bcogc.ca](mailto:EMP@bcogc.ca)  
250-794-5230



## INCIDENT REPORTING INSTRUCTIONS AND GUIDELINES

### SPILL REPORTING CRITERIA

Where the permit holder holds or maintains rights, the permit holder must report to the BC Oil and Gas Commission, all spills of materials as identified below:

- A spill or release of any amount of materials which impacts water ways
- Hydrocarbons; 100 litres where the hydrocarbon contains no toxic materials and does not impact water ways
- Produced/salt water; 200 litres where the fluid contains no toxic materials
- Fresh water; 10,000 litres
- Drilling or invert mud; 100 litres
- Sour Natural gas; 10Kg or 15 m<sup>3</sup> by volume where operating pressure is >100 PSI
- Condensate; 100 litres
- Any fluid including hydrocarbons, drilling fluids, invert mud, effluent, emulsions, etc. which contain toxic substances; 25 litres

Please refer to the BC Environmental Management Act; Spill Reporting Regulations, Schedule "Reporting Levels for Certain Substances" for determining reportable spillage amounts of other substances:

[http://www.bclaws.ca/EPLibraries/bclaws\\_new/document/ID/freeside/46\\_263\\_90](http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/46_263_90)

Even though some spills are not reportable, the requirement to clean up the spill is still mandatory. Spills of reportable amounts which occur in a secondary containment are still a reportable incident.

### OTHER REPORTABLE INCIDENTS

The Commission's Incident Classification Matrix is designed to assist permit holders in determining which incidents must be reported. However, some incidents, which do occur, may not meet the criteria outlined in the Incident Classification Matrix but still require notification to the Commission as a minor notification.

These include the following:

- Spills or release of hazardous substances which are not provincially regulated, such as radioactive substances;
- Major damage to oil and gas roads or road structures;
- Drilling kicks when any one of the following occur:
  - pit gain of 3 m<sup>3</sup> or greater
  - casing pressure 85% of MA
  - 50% out of hole when kicked
  - well taking fluid (LC)
  - associated spill
  - general situation deterioration, i.e. leaks, equipment failure, unable to circulate, etc.
- Pipeline incidents, such as spills during construction phase, exposed pipe caused by flooding, pipeline over pressure, failure (without release) of any pressure control or ESD device during operations, and;
- Security related issues which are relatively minor; such information may be required for tracking and monitoring purposes only.

### INCIDENT REPORTING INSTRUCTIONS

The Incident Classification Matrix is designed for use as a tool for determining the severity of an incident. The ranking system includes quantitative analyses of 1) the consequence(s) as a result of the incident, and 2) the likelihood of the incident escalating.

1. Complete the scoring by starting at the top and continue down. Check off any one box for consequence and probability.
2. Add the applicable scores from each section. Note if none of the check box items apply in either section, the rank should be recorded as "zero".
3. Compare the total score with the classification section and assign the corresponding level.

## **MINOR INCIDENT**

- The permit holder must report the minor incident to the Commission within **24 hours** by electronic submission through the [Online Minor Incident Reporting System](#), operated through KERMIT.
- If the minor incident involves a spill, EMBC must also be called at 1-800-663-3456 for the Ministry of Environment to be notified.
- The incident must be reported by electronic submission by the permit holder incident representative. A copy of the Form A: Minor Incident Notification Form and the Incident Classification Matrix can be found on the Emergency Response and Safety section of the Commission's website to help the permit holder gather the information required before entering it online. The matrix and any photos or any other relevant documentation can be attached to the online submission.

## **LEVEL 1, 2, OR 3 EMERGENCY**

If the incident receives a score of Level 1, 2, or 3, it must be reported **immediately (within 1 hour)** to the Commission's incident reporting line (EMBC 1-800-663-3456).

## **OIL AND GAS ROAD CLOSURES**

In Emergency situations, permit holders must phone the Commission's 24 hour Incident Reporting line to notify the Commission of needed emergency oil and gas road closures.

## **PERMIT HOLDER POST INCIDENT REPORT**

The [Form D: Permit Holder Post Incident Report Form](#) must be submitted by the permit holder to the Commission within 60 days for:

1. Any Level 1, 2 or 3 emergency incident: complete Part A-P; or
2. Any pipeline incident (including minor incident): complete Part A-U; or
3. Upon request by the Commission.

This report and accompanying documentation can be found on the Commission's website under Emergency Response and Planning and must be emailed electronically to [EMP@bcogc.ca](mailto:EMP@bcogc.ca)

## INCIDENT CLASSIFICATION MATRIX

**Instructions:** Start at the top and continue down until you check off any one box in both consequence and probability to determine the incident classification. *This matrix is required as an attachment upon submission of an incident through the [Online Minor Incident Reporting System](#).*

**TABLE 1. CONSEQUENCE RANKING**

RANK	CONSEQUENCE (any one of the following)
4	<input type="checkbox"/> Major on site equipment or infrastructure loss <input type="checkbox"/> Major act of violence, sabotage, or terrorism which impacts permit holder assets <input type="checkbox"/> Reportable liquid spill beyond site, uncontained and affecting environment <input type="checkbox"/> Gas release beyond site affecting public safety
3	<input type="checkbox"/> Threats of violence, sabotage, or terrorism <input type="checkbox"/> Reportable liquid spill or gas release beyond site, potentially affecting public safety, environment, or property <input type="checkbox"/> HAZMAT worker exposure exceeding allowable <input type="checkbox"/> Major on site equipment failure
2	<input type="checkbox"/> Major on site equipment damage <input type="checkbox"/> A security breach that has potential to impact people, property or the environment <input type="checkbox"/> Reportable liquid spill or gas release potentially or beyond site, not affecting public safety, environment, or property
1	<input type="checkbox"/> Moderate on site equipment damage <input type="checkbox"/> A security breach that impacts oil and gas assets <input type="checkbox"/> Reportable liquid spill or gas release on location <input type="checkbox"/> **Occurrence of magnitude 4.0 or greater induced earthquake within 3 km of oil and gas operations or any earthquake which is felt on surface within a 3 km radius of oil and gas operations
0	<input type="checkbox"/> No consequential impacts

\*\* For this consequence criteria, a probability score of 2 or higher must be used.

**TABLE 2. PROBABILITY RANKING**

RANK	PROBABILITY (any one of the following)
4	<input type="checkbox"/> Uncontrolled, with control unlikely in near term
3	<input type="checkbox"/> Escalation possible; under or imminent control
2	<input type="checkbox"/> Escalation unlikely; controlled or likely imminent control
1	<input type="checkbox"/> Escalation highly unlikely; controlled or imminent control
0	<input type="checkbox"/> Will not escalate; no hazard; no monitoring required

**TABLE 3. INCIDENT RISK SCORE AND CLASSIFICATION**

CONSEQUENCE \_\_\_\_\_ + PROBABILITY \_\_\_\_\_ = RISK SCORE \_\_\_\_\_ (this must be completed)

RISK SCORE	ASSESSMENT RESULT
Minor (1-2)	<b>Notification Only;</b> permit holder must notify the Commission online within 24 hours using the <a href="#">Form A: Minor Incident Notification Form</a> . In addition to Form A, spills must also be reported to EMBC.
Moderate (3-4)	<b>Level-1 Emergency;</b> immediate notification (call EMBC)
Major (5-6)	<b>Level-2 Emergency;</b> immediate notification (call EMBC)
Serious (7-8)	<b>Level-3 Emergency;</b> immediate notification (call EMBC)

SEE OVER

## SPILL REPORTING CRITERIA

Where the permit holder holds or maintains rights, the permit holder must report to the BC Oil and Gas Commission, all spills of materials as identified below:

- A spill or release of any amount of materials which impacts water ways
- Hydrocarbons; 100 litres where the hydrocarbon contains no toxic materials and does not impact water ways
- Produced/salt water; 200 litres where the fluid contains no toxic materials
- Fresh water; 10,000 litres
- Drilling or invert mud; 100 litres
- Sour Natural gas; 10Kg or 15 m<sup>3</sup> by volume where operating pressure is >100 PSI
- Condensate; 100 litres
- Any fluid including hydrocarbons, drilling fluids, invert mud, effluent, emulsions, etc. which contain toxic substances; 25 litres

Please refer to the BC Environmental Management Act; [Spill Reporting Regulation](#), Schedule “Reporting Levels for Certain Substances” for determining reportable spillage amounts of other substances:

## OTHER REPORTABLE INCIDENTS

The Commission’s Incident Risk Classification Matrix is designed to assist permit holders in determining which incidents must be reported. However, some incidents, which do occur, may not meet the criteria outlined in the Incident Classification Matrix but still require notification to the Commission as a minor notification. These include the following:

- Spills or release of hazardous substances which are not provincially regulated, such as radioactive substances;
- Major damage to oil and gas roads or road structures;
- Drilling kicks when any one of the following occur:
  - pit gain of 3 m<sup>3</sup> or greater
  - casing pressure 85% of MA
  - 50% out of hole when kicked
  - well taking fluid (LC)
  - associated spill
  - general situation deterioration, i.e. leaks, equipment failure, unable to circulate, etc
- Pipeline incidents, such as spills during construction phase, exposed pipe caused by flooding, pipeline over pressure, failure (without release) of any pressure control or ESD device during operations
- Security related issues which are relatively minor; such information may be required for tracking and monitoring purposes only



## OGC Incident Classification Matrix

Consequence

		Probability					
		4	3	2	1	0	
		<input type="checkbox"/> Uncontrolled, with control unlikely in near term	<input type="checkbox"/> Escalation possible; under or imminent control	<input type="checkbox"/> Escalation unlikely; controlled or likely imminent control	<input type="checkbox"/> Escalation highly unlikely; controlled or imminent control	<input type="checkbox"/> Will not escalate; no hazard; no monitoring required	
Consequence	4	<input type="checkbox"/> Major on site equipment or infrastructure loss <input type="checkbox"/> Major act of violence, sabotage, or terrorism which impacts permit holder assets <input type="checkbox"/> Reportable liquid spill beyond site, uncontained and affecting environment <input type="checkbox"/> Gas release beyond site affecting public safety	Level 3	Level 3	Level 2	Level 2	Level 1
	3	<input type="checkbox"/> Threats of violence, sabotage, or terrorism <input type="checkbox"/> Reportable liquid spill or gas release beyond site, potentially affecting public safety, environment, or property <input type="checkbox"/> HAZMAT worker exposure exceeding allowable <input type="checkbox"/> Major on site equipment failure	Level 3	Level 2	Level 2	Level 1	Level 1
	2	<input type="checkbox"/> Major on site equipment damage <input type="checkbox"/> A security breach that has potential to impact people, property or the environment <input type="checkbox"/> Reportable liquid spill or gas release potentially or beyond site, not affecting public safety, environment, or property	Level 2	Level 2	Level 1	Level 1	Minor Notification Form
	1	<input type="checkbox"/> Moderate on site equipment damage <input type="checkbox"/> A security breach that impacts oil and gas assets <input type="checkbox"/> Reportable liquid spill or gas release on location <input type="checkbox"/> ** Occurrence of magnitude 4.0 or greater induced earthquake within 3 km of oil and gas operations or any earthquake which is felt on surface within a 3 km radius of oil and gas operations	Level 2	Level 1	Level 1	Minor Notification Form	Minor Notification Form
	0	<input type="checkbox"/> No consequential impacts	Level 1	Level 1	Minor Notification Form	Minor Notification Form	No notification Required

**\*\* For this consequence criteria, a probability score of 2 or higher must be used.**