FORTIS BC™

Diane Roy
Director, Regulatory Affairs - Gas
FortisBC Energy Inc.

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

October 15, 2012

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

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. ("FEI")

Application for Approval of Rate Treatment of Expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation ("GGRR") and Prudency Review of Incentives under the 2010 – 2011 Commercial NGV Demonstration Program (the "Application")

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 1

On August 21, 2012, FEI filed the Application as referenced above. In accordance with the Regulatory Timetables set out by Commission Order No. G-125-12 for Phase 1 and Order No. G-127-12 for Phase 2, FEI respectfully submits the attached response to CEC IR No. 1.

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

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Shawn Hill

For: Diane Roy

Attachment

cc (e-mail only): Commission Secretary
Registered Parties

1. Exhibit B-1, Page 4

As outlined in Section 5, in this Application FEI seeks approval of the following two deferral accounts:

1. A non-rate base deferral account (the "NGT Incentives Account") attracting AFUDC to capture: (a) all grants and costs, including a portion of application costs, related to Prescribed Undertaking 1 for the period until December 31, 2013; and (b) to capture the 2010-2011 Incentives in the amount of $5.6 million. This account is to be transferred to rate base, effective January 1, 2014, and will continue to capture the actual incentives granted under Prescribed Undertaking 1 and will be amortized over a 10 year period into the delivery rates of all non-bypass natural gas customers; and

1.1 What is the basis for the determination of the $5.6 million?

Response:

Since the use of natural gas in heavy duty commercial vehicles had not been widely adopted in BC, FEI provided EEC incentives in 2010 as part of the Commercial NGV Demonstration program. Projects using both CNG and LNG were selected to demonstrate a complete fuelling solution for potential fleet customers. These initiatives were provided as demonstration programs in order to gather data such as fuel consumption, fuel efficiency, and vehicle performance. This data was intended to help FEI and fleet owners determine the most cost-effective and beneficial method of re-introducing natural gas vehicles in BC. The recovery of the $5.6 million is being addressed in Phase 3 of this proceeding and can be addressed in more detail at that time.

1.2 Please describe the components of the $5.6 million.

Response:

The components of the $5.6 million incentive funding are detailed in Table 7-1 of the Application. Table 7-1 is also provided below for ease of reference. The $5.6 million will be the subject of Phase 3 of this proceeding.

Customer Receiving NGV Incentive	Incentive Amount Committed ($)	Date of Agreement for EEC Incentive Funding (MM/DD/YYYY)	Estimated Fuel Savings to Customer ($)	Customer Estimated Avoided Diesel (L)	Customer Estimated GHG Reductions (tonnes)	Estimated Revenue to FortisBC Energy ($)	Total Resource Cost (TRC) Test Ratio
City of Surrey	$ 26,700	9/15/2010	$ 18,566	34,000	13	$ 5,611	1.7
Kelowna School District	$ 363,286	3/17/2011	$ 17,587	95,436	120	$ 21,888	1.1
Waste Management	$ 803,560	12/3/2010	$ 202,651	468,000	214	$ 38,728	1.4
Vedder Transport	$ 4,393,300	12/10/2010	$ 1,877,989	3,582,850	3,754	$ 548,460	1.4
Total	$ 5,586,846		$ 2,116,793	4,180,286	4,100	$ 614,687	

1.3 How was the 10 year amortization period determined?

Response:

This response also addresses CEC IR 1.1.4.

As discussed in section 5.2.4 of the Application, FEI considered the life of the CNG and LNG vehicles, the duration of the expected benefits, as well as rate volatility in the determination of the proposed amortization period for the NGT Incentives Account.

FEI considers a ten year amortization period to be an appropriate time frame for amortization as this approximates the expected life of the CNG/LNG vehicles as well as the period over which the benefits of the program are experienced.[1] This meets the ratemaking and accounting objective of matching costs and benefits and in turn achieves the concept of intergenerational equity. Further, the proposed approach also avoids the rate volatility that would occur with an expensing approach.

1.4 What is the basis for the 10 year amortization period?

[1] The benefits to other natural gas customers of increased throughput from NGV load may well continue beyond the end of the vehicle life without the need for additional incentives as operators replace their first natural gas-fuelled vehicles with new natural gas-fuelled vehicles.

Response:

Please refer to the response to CEC IR 1.1.3.

1.5 Please show the rate impacts of a 10 year, 20 year and 30 year amortization period.

Response:

Please refer to the table below which provides the cumulative rate impact per year for the three amortization periods for both Scenario 1 (expected case) and Scenario 2 (low growth case). Please also note that Appendix G (Scenario 1) and H (Scenario 2) of the Application as filed reflect a ten year amortization period.

As noted in the response CEC IR 1.1.3, FEI believes that a ten year amortization period is appropriate for this account because it balances the recovery of costs over a reasonable period with the expected duration of benefits and rate impacts of the vehicle incentives.

Year	Scenario 1 Amortization Period 10 Year	20 Year	30 Year	Scenario 2 Amortization Period 10 Year	20 Year	30 Year
2014	0.14%	(0.01%)	(0.06%)	0.14%	(0.01%)	(0.06%)
2015	0.24%	(0.01%)	(0.09%)	0.24%	(0.01%)	(0.09%)
2016	0.20%	(0.11%)	(0.22%)	0.20%	(0.11%)	(0.22%)
2017	0.08%	(0.29%)	(0.42%)	(0.01%)	(0.38%)	(0.51%)
2018	0.68%	0.29%	0.16%	0.05%	(0.34%)	(0.47%)
2019	0.31%	(0.04%)	(0.16%)	(0.04%)	(0.39%)	(0.51%)
2020	(0.11%)	(0.42%)	(0.52%)	(0.13%)	(0.44%)	(0.55%)
2021	(0.58%)	(0.86%)	(0.95%)	(0.22%)	(0.49%)	(0.58%)
2022	(1.12%)	(1.36%)	(1.44%)	(0.30%)	(0.54%)	(0.62%)
2023	(1.18%)	(1.38%)	(1.45%)	(0.38%)	(0.59%)	(0.66%)
2024	(1.60%)	(1.52%)	(1.58%)	(0.71%)	(0.63%)	(0.69%)
2025	(2.02%)	(1.76%)	(1.81%)	(0.94%)	(0.68%)	(0.72%)
2026	(2.57%)	(2.16%)	(2.19%)	(1.13%)	(0.72%)	(0.76%)
2027	(3.23%)	(2.70%)	(2.72%)	(1.29%)	(0.76%)	(0.79%)
2028	(4.04%)	(3.45%)	(3.46%)	(1.39%)	(0.80%)	(0.82%)
2029	(4.95%)	(4.40%)	(4.40%)	(1.39%)	(0.84%)	(0.85%)
2030	(5.59%)	(5.07%)	(5.07%)	(1.39%)	(0.88%)	(0.87%)

1.6 Would it be correct to say that the $5.6 million has been an initial investment in a market transformation process yet to evolve fully?

Response:

Yes, the initial $5.6 million was the first investment to initiate the market transformation. The results of the initial investment have been what the program was designed to do. Specifically the initial investment:

- Generated over 210,000 GJ of system load which provides delivery rate benefits to all non-bypass customers.
- Led to the successful operational demonstrations of heavy duty NGVs in the BC market involving a total of 82 vehicles in 4 different transportation segment applications. All operators are pleased with the success of the vehicles and are generating savings

versus their diesel fueled vehicles. In addition the vehicles are generating GHG reductions between 20 and 30% versus conventional vehicles.

- Led to follow on orders for 52 additional heavy duty NGVs that were purchased without the benefit of incentives. (The Surrey RFP for waste collection services mandated the use of NGV. This RFP was issued after Surrey gained confidence in NG waste collection vehicles using a vehicle partially funded under the original program). This added a further 60,000 GJ/yr of load bringing the total to more than 265,000 GJ/yr.

- Led to over 30 applications for the second round of the program, where incentives are reduced to 75%. Potential demand from this round is 401 vehicles consuming 1,250,000 GJ/yr (1.25 PJ/yr). This phase would displace approximately 28 million litres per year of diesel fuel consumption and reduce GHGs by approximately 35,000 tonnes per year.

2. Exhibit B-1, Page 4

> FEI is also seeking approval from the Commission of the accounting and rate treatment methodology to be applied to these deferral accounts and the related expenditures associated with the three prescribed undertakings identified in the GGRR for the current period of the 2012-2013 RRA and for future years as described in Section 5 of this Application. The methodology entails recovering program costs from all non-bypass FEI customers. This is an appropriate methodology because all non-bypass customers receive benefits through lower delivery rates and reduced GHG emissions and the program is consistent with government policy.

2.1 Please provide a cost benefit analysis for the non-bypass customer showing their estimated benefits versus their estimated costs.

Response:

The cost benefit analyses for non-bypass customers have been provided for Scenarios 1 and 2 in Appendices G and H respectively. The summary of annual costs and benefits is found in Schedule 1 of those appendices. The costs are presented on line 10, and the benefits on line 9. The net cost / benefit is found on line 11.

3. Exhibit B-1, Appendix J, Page 5

Table 6: Scenario 1 Cumulative Delivery Rate Impacts (%) 2014-2030

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Impact	0.14%	0.24%	0.20%	0.08%	0.68%	0.31%	(0.11)%	(0.58)%	(1.12)%
	2023	2024	2025	2026	2027	2028	2029	2030	
Rate Impact	(1.18)%	(1.60)%	(2.02)%	(2.57)%	(3.23)%	(4.04)%	(4.95)%	(5.59)%	

Table 6 shows that delivery rate impacts fluctuate slightly in the first few years of the program because incremental volumes are not yet great enough to offset the costs of incentives and the administration of the NGT Incentive Program, as well as the costs of additional LNG liquefaction and storage forecast to occur in 2017. However, FEI customers will start to realize the benefit of the incentive funding program in 2020. By 2020, delivery rates are forecast to decrease by 0.11% as a result of this program, and will continue to decrease after that point as volumes increase. Detailed rate impact tables have been included in Appendix G, Schedule 1.

3.1 Please confirm that Appendix G schedule 1financials is the planned future as of this time.

Response:

Confirmed.

3.2 Please provide the percentage conversion of the estimated market for NGT this plan would represent and provide the quantitative supporting analysis.

Response:

Table 6 in Appendix J is based on volumes from Table 5 in Appendix J, which show an annual volume of 25 PJ by 2030.

FEI has previously calculated its target market size in FEI's CNG/LNG Service Application, at Appendix A-1, Section 2. The underlying market size assumptions were derived from a 2007 Natural Resources Canada energy use database which remains the best available resource for categorized vehicle energy use in British Columbia. In 2010, FEI's target market assessment included the following categories, in 2007 energy values:

- Passenger cars 66 PJ;
- Light duty trucks 78 PJ;
- Medium trucks 20 PJ;
- Heavy duty trucks 66 PJ;
- Buses 5 PJ; and
- Marine vessels 54 PJ.

These categories total approximately 290 PJ (2007) and projected to 458 PJ by 2030 (escalated at 2% growth rate per year).

At present FEI is no longer targeting the passenger cars segment and opportunities within the light duty trucking segment are not a primary focus. As well, the eligible vehicle categories under the GGRR are limited to medium trucks, heavy duty trucks, buses and marine vessels.

FEI has removed these values from the target market assessment which results in market size of 146 PJ in 2007, which projects to 230 PJ by 2030. Thus the 25 PJ of expected volume additions under the GGRR presented in this Application represents roughly 11 percent market penetration of the FEI's target market by 2030.

FEI also notes that the forecast presented in this Application is based on the best available information at this time. A number of challenges exist in developing a long-term demand forecast as NGT is still the early stages of adoption in BC. FEI will continue to develop its methodologies for forecasting demand when more NGT projects advance. The accumulation of actual adoption data can assist in more accurately forecasting future trends.

3.3 Please advise what FEI could do to make the program pay-off faster than is currently planned.

Response:

The program pay off timing depends on two primary variables. The first is the amount of incentive funding invested and the second is the load addition. To minimize the investment in incentives FEI has designed a program where incentives are reduced year by year in every year of the program. This results in early adopter applicants that are willing to accept the risks of adopting a new fuel, stepping forward to be part of the program before incentives decline. It also allows FEI to maximize the number of vehicles brought into service as it minimizes potential for free riders. The end result is that program payoff timing can be optimized.

For example, where demand under the program is strong, the amount of the incentive per vehicle can be reduced to stimulate a greater number of vehicles. FEI's initial intention for the 2012 round of incentives was to provide funding up to 80%. The actual preliminary awards are being set at 75%.

FEI will continue to monitor the uptake of vehicles under the program and to adjust the incentives as appropriate to make the program pay off as soon as possible.

Another thing that FEI can do to maximize payoff is to attract applications from high utilization vehicles that use large amounts of fuel.

3.4 Please discuss the intergenerational equity issues related to the initial subsidy incentive being used to transform the market.

Response:

Intergenerational equity usually refers to the particular goal of attempting to match costs to the period in which the benefit is provided that gave rise to the cost. The kinds of issues that raise intergenerational equity concerns are those that either benefit future customers at the expense of current customers, or burden future customers to the benefit of current customers. As with other rate design issues and principles there is not a bright line determinant of what constitutes enough intergenerational inequity to push rates outside the bounds of being just and reasonable or not unduly discriminatory. Commissions must weigh intergenerational equity concerns along with other rate design principles and issues to arrive at an overall decision based on the facts and evidence before them in any given case.

In this case, FEI believes it has proposed rate recovery principles for GGRR vehicle incentives that find a fair balance with respect to intergenerational equity. The grants under FEI's NGT incentive program are to be amortized over a ten-year timeframe as this approximates the expected life of CNG/LNG vehicles. This mitigates the impact on current customers' delivery rates as shown in Table 6. In FEI's proposal, which uses a ten-year amortization period for incentives, the delivery charge rate impact between 2014 and 2019 is less than 1% in each year and this is offset by higher decreases (over a similar 6 year period) in the delivery rate beginning in 2020. This would confirm that intergenerational inequity is not a large concern and that current customers are not being significantly impacted.

As indicated in Exhibit B-1, page 20, section 5.2.4, intergenerational equity would be a much greater concern for this program if the costs were simply expensed in a single year since current customers would bear all the costs but future customers would obtain the benefits.

3.5 Please explain why Appendix H Schedule 1 shows lower impacts on existing customers for a low growth scenario than for Appendix G Schedule 1 for the planned growth scenario.

Response:

For the years 2014 through 2016 the rate impacts are the same for both Scenarios 1 and 2 since the load growth and costs are the same to that point. For the years 2017 onward Scenario 1 has higher growth which would require incremental LNG production to meet the demand forecast. The cost of service for the additional LNG production facilities would initially reduce the benefit to ratepayers in years 2017 to 2020. However, for years 2021 onward the growth benefits outweigh the costs and ratepayers see a greater benefit (reduction on rates) under Scenario 1 (Appendix G).

3.6 Do the scenarios anticipate FEI Amalco and if not could updated schedules for Appendix G & H be provided incorporating the FEI Amalco concepts?

Response:

The approximate rate impact to customers on an FEU amalgamated basis would be smaller in percentage terms than the rate impact to FEI customers provided in this Application since the combined Amalco volumes and delivery margins are larger than FEI's alone, meaning the costs of the NGT Incentive Program would being spread across a larger customer base. For example, in 2018 the NGT Incentive Program has an estimated rate impact of approximately 0.68% when allocated to FEI only, but the impact is approximately 0.51% when allocated to all FEU customers.

The following assumptions have been used to recast Appendices G and H assuming that FEU is an amalgamated regulated entity:

- Delivery rates used to calculate margins using Amalco concepts can be found in the "FEU Common Rates, Amalgamation and Rate Design", Exhibit B-3-1, Appendix J-3;
- The Capital Structure used to calculate the earned return using Amalco concepts can be found in the "FEU Common Rates, Amalgamation and Rate Design", Exhibit B-3-1, Appendix J-2;
- Delivery Margin Denominator: The rate impact is calculated by dividing the forecast net annual cost of service benefit (cost) divided by total forecast delivery margin. Using Amalco concepts, the total forecast delivery margin increases as it includes Fortis Energy Inc. (FEI), Fortis Energy Vancouver Island (FEVI), Fortis Energy Whistler (FEW) and Fort Nelson (FN); and
- The following schedules assume amalgamation commencing January 1, 2014.

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012 -2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, unless otherwise stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012 -2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)	Sch 2, Line 8	178	458	917	1,416	2,032	2,882	3,407	4,027	4,760	5,626
2												
3	Discount Rate	2014 FEI After-Tax WACC	6.69%									
4	Discount Period (years)		1	2	3	4	5	6	7	8	9	10
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1	575	577	744	758	774	789	805	821	837	854
7												
8	Net COS Benefit (Cost) to Existing Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volume	Sch 2, Line 40, Note 2,4	538	1,284	2,701	4,113	6,061	8,838	13,143	15,843	19,102	23,033
10	Annual Incentive Funding COS	Sch 3, -Line 76			(3,456)	(5,427)	(7,128)	(9,116)	(17,260)	(17,591)	(18,076)	(18,750)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	538	1,284	(755)	(1,314)	(1,067)	(278)	(4,117)	(1,748)	1,026	4,283
12												
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3			0.10%	0.17%	0.14%	0.04%	0.51%	0.21%	(0.12)%	(0.50)%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	505	1,128	(622)	(1,014)	(772)	(189)	(2,617)	(1,041)	573	2,241
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	505	1,633	1,011	(3)	(775)	(964)	(3,580)	(4,622)	(4,049)	(1,808)
18												
19	NPV of Net COS Benefit (Cost) 2012 to 2030 (19 Years)			71,382								

20 Note:
21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,
22 does not include any impact of the prescribed undertaking expenditures or prior incentives
23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32
24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives
25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, unless otherwise stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)

		Reference		2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)	Sch 2, Line 8		6,650	7,861	9,291	10,982	12,981	15,344	18,136	21,437	25,338
2												
3	Discount Rate	2014 FEI After-Tax WACC										
4	Discount Period (years)			11	12	13	14	15	16	17	18	19
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1		871	889	906	924	943	962	981	1,001	1,021
7												
8	Net COS Benefit (Cost) to Existing Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volume	Sch 2, Line 40, Note 2,4		27,766	33,479	40,361	48,661	58,670	70,730	85,283	102,815	123,966
10	Annual Incentive Funding COS	Sch 3, -Line 76		(19,654)	(24,741)	(28,326)	(33,202)	(38,714)	(45,196)	(52,776)	(62,230)	(77,137)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10		8,111	8,738	12,035	15,459	19,956	25,534	32,507	40,585	46,829
12												
13	Approximate Annual FEI Delivery (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3		(0.93)%	(0.98)%	(1.33)%	(1.67)%	(2.12)%	(2.65)%	(3.31)%	(4.06)%	(4.59)%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)		3,979	4,018	5,186	6,244	7,555	9,061	10,812	12,652	13,683
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year		2,171	6,189	11,375	17,619	25,174	34,235	45,047	57,699	71,382

18

19

20 Note:

21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,

22 does not include any impact of the prescribed undertaking expenditures or prior incentives

23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32

24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives

25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part A: Benefits (2012-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part A: Benefits (2012-2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)											
2	Rate 16 not included in RRA 2012/13		12	183	698	1,036	1,482	2,103	2,486	2,938	3,473	4,105
3	Rate 16 included in RRA 2012/13	Note 8	139	139								
4	Rate 23 not included in RRA 2012/13		1	1	15	27	39	55	64	76	90	106
5	Rate 23 included in RRA 2012/13	Note 8	6	6								
6	Rate 25 not included in RRA 2012/13		2	110	204	353	512	725	857	1,012	1,197	1,415
7	Rate 25 included in RRA 2012/13	Note 8	19	19								
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	178	458	917	1,416	2,032	2,882	3,407	4,027	4,760	5,626
9	Number of CNG Stations											
10	Rate 23		-	-	-	-	1	1	1	1	1	1
11	Rate 25		1	3	5	8	11	15	18	21	25	30
12	Number of LNG Stations		2	3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	8	378	698	1,210	1,752	2,482	2,934	3,467	4,098	4,844
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	65	65								
15	Volumetric Delivery Rates ($/GJ)	Note 2										
16	Rate 16 (Net of incremental costs) Note 3 & 12	2012 & 2013 approved	3.25	3.29	3.28	3.27	3.36	3.47	4.54	4.63	4.72	4.81
17	Rate 23	2012 & 2013 approved	2.44	2.62	2.95	3.01	3.07	3.13	3.20	3.26	3.33	3.39
18	Rate 25	2012 & 2013 approved	0.68	0.73	0.85	0.86	0.88	0.90	0.91	0.93	0.95	0.97
19	Demand Rates	Note 2										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	16.82	18.06	20.23	20.63	21.05	21.47	21.90	22.34	22.78	23.24
21	Basic & Admin Charge	Note 2, 7										
22	Rate 23 $/Month	2012 & 2013 approved	210.52	210.52	210.52	214.73	219.03	223.41	227.87	232.43	237.08	241.82
23	Rate 25 $/Month	2012 & 2013 approved	665.00	665.00	665.00	678.30	691.87	705.70	719.82	734.21	748.90	763.88
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part B: Benefits (2012-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part B: Benefits (2012-2021)

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Incremental Margin '000$											
27	*Delivery*											
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	37	604	2,288	3,386	4,988	7,291	11,277	13,596	16,391	19,762
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	450	456								
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	2	2	45	80	118	171	206	249	300	361
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	15	16								
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	2	81	172	305	450	650	783	945	1,139	1,373
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	13	14								
34	*Demand*											
35	Rate 25 not included in RRA 2012/13	(Line 13 x Line 20x12/1000)	2	82	169	300	442	639	771	929	1,120	1,351
36	Rate 25 included in RRA 2012/13	(Line 14 x Line 20x12/1000)	13	14								
37	*Basic Charges*											
38	Rate 23 + 25	Note 6	5	16	27	43	63	86	105	125	152	185
39	Rate 16		-	-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	538	1,284	2,701	4,113	6,061	8,838	13,143	15,843	19,102	23,033
41	Cumulative Incremental Margin		538	1,822	4,524	8,637	14,698	23,536	36,679	52,522	71,624	94,656

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + Line 11 x (Line 23 x 12) /1000x(2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25/16 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000
55 12 Add $1/GJ in 2018 to fund incremental LNG liquefaction and storage

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part A: Benefits (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part A: Benefits (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)										
2	Rate 16 not included in RRA 2012/13		4,852	5,736	6,779	8,013	9,472	11,196	13,233	15,642	18,488
3	Rate 16 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
4	Rate 23 not included in RRA 2012/13		126	149	176	208	246	290	343	406	480
5	Rate 23 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
6	Rate 25 not included in RRA 2012/13		1,672	1,976	2,336	2,761	3,264	3,858	4,560	5,390	6,371
7	Rate 25 included in RRA 2012/13	Note 8	-	-	-	-	-	-	-	-	-
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	6,650	7,861	9,291	10,982	12,981	15,344	18,136	21,437	25,338
9	Number of CNG Stations										
10	Rate 23		1	1	2	2	2	2	2	2	2
11	Rate 25		35	42	49	58	69	81	97	114	136
12	Number of LNG Stations		35	41	49	58	68	80	95	112	133
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	5,726	6,768	8,000	9,456	11,177	13,211	15,616	18,458	21,817
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	-	-	-	-	-	-	-	-	-
15	Volumetric Delivery Rates ($/GJ)	Note 2									
16	Rate 16 (Net of incremental costs) Note 3 & 1:	2012 & 2013 approved	4.91	5.01	5.11	5.21	5.31	5.42	5.53	5.64	5.75
17	Rate 23	2012 & 2013 approved	3.46	3.53	3.60	3.67	3.75	3.82	3.90	3.98	4.06
18	Rate 25	2012 & 2013 approved	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
19	Demand Rates										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	23.70	24.18	24.66	25.15	25.66	26.17	26.69	27.23	27.77
21	Basic & Admin Charge	Note 2, 7									
22	Rate 23 $/Month	2012 & 2013 approved	246.66	251.59	256.62	261.76	266.99	272.33	277.78	283.33	289.00
23	Rate 25 $/Month	2012 & 2013 approved	779.15	794.74	810.63	826.84	843.38	860.25	877.45	895.00	912.90
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part B: Benefits (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 2, Part B: Benefits (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Incremental Margin '000$										
27	*Delivery*										
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	23,826	28,726	34,633	41,755	50,341	60,693	73,174	88,221	106,363
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	-	-	-	-	-	-	-	-	-
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	436	525	633	763	920	1,110	1,338	1,613	1,945
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	-	-	-	-	-	-	-	-	-
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	1,655	1,996	2,406	2,901	3,498	4,217	5,084	6,129	7,390
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	-	-	-	-	-	-	-	-	-
34	*Demand*										
35	Rate 25 not included in RRA 2012/13	(Line 13 x Line 20x12/1000)	1,629	1,964	2,367	2,854	3,441	4,149	5,002	6,031	7,271
36	Rate 25 included in RRA 2012/13	(Line 14 x Line 20x12/1000)	-	-	-	-	-	-	-	-	-
37	*Basic Charges*										
38	Rate 23 + 25	Note 6	220	269	322	388	470	562	685	821	998
39	Rate 16		-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	27,766	33,479	40,361	48,661	58,670	70,730	85,283	102,815	123,966
41	Cumulative Incremental Margin		122,422	155,901	196,263	244,924	303,594	374,324	459,607	562,422	686,388

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + Line 11 x (Line 23 x 12) /1000x(2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25/16 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000
55 12 Add $1/GJ in 2018 to fund incremental LNG liquefaction and storage

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts

Schedule 3, Part A: Cost of Service (2011-2021)

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts

Schedule 3, Part A: Cost of Service (2011-2021)

Market expands, additional LNG equipment (liquefaction and storage) added to meet demand

$000's, Unless Otherwise Stated

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Key Assumptions												
2	Rates												
3	ROE %	BCUC Order No. G-44-12	9.50%	9.50%	9.50%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
4	STD Rate %	BCUC Order No. G-44-12	4.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate %	BCUC Order No. G-44-12	6.95%	6.85%	6.87%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
6	Capital Structure												
7	Equity %	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	1.63%	1.93%	3.03%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
9	LTD %	BCUC Order No. G-44-12	58.37%	58.07%	56.97%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base %	Note 5	7.93%	7.83%	7.82%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
12	WACC %	Note 6	6.84%	6.82%	6.81%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%
13	Tax Rate %		26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1											
15	Prior Vehicle Incentives	Note 10	5,573										
16	Vehicle & Marine		-	7,843	11,479	10,404	9,807	9,794	-				
17	Maintenance Upgrades & Safety		-	200	950	950	950	950	-				
18	Admin, Marketing, Train, Education		-	300	1,000	900	600	300	-				
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	5,573	8,343	13,429	12,254	11,357	11,044	-				
20	Incentive Payouts (Cash Basis)	Note 1											
21	Prior Vehicle Incentives		5,573										
22	Vehicle & Marine	Note 1	-	1,961	8,752	11,210	10,255	9,804	7,345				
23	Maintenance Upgrades & Safety	Note 1		50	922	950	950	1,128	-				
24	Admin, Marketing, Train, Education	Note 1		300	1,000	900	600	300	-				
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	5,573	2,311	10,674	13,060	11,805	11,232	7,345				

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part B: Cost of Service (2011-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part B: Cost of Service (2011-2021)

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Non Rate Base Deferral Account (NRBDA) Calculation												
27	Gross Additions	Line 25 (2011-2013)	5,573	2,311	10,674								
28	Tax	- Line 27 x Line 13	(1,477)	(578)	(2,668)	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	4,097	1,733	8,005	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	4,097	5,851								
31	Net Additions	Line 29	4,097	1,733	8,005								
32	Incremental Margins pre 2014	Note 7	-	(36)	(588)								
33	AFUDC on Deferral Account pre 2014	Note 4, 11	-	58	579								
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	4,097	5,851	13,847								
35	Rate Base Deferral Account Calculation												
36	Amortization Period (Years)		10										
37	Gross Additions	Line 25 (2014+)				13,060	11,805	11,232	7,345	-	-	-	-
38	Tax	- Line 37 x Line 13				(3,265)	(2,951)	(2,808)	(1,836)	-	-	-	-
39	Net Additions	Line 37 + Line 38				9,795	8,854	8,424	5,509	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years				980	885	842	551	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2				13,847							
42	Annual Amortization of NRBDA	Line 41/10 years				1,385							
43	Opening Deferral Account Balance	Note 8				13,847	22,258	28,747	33,921	35,338	30,695	26,053	21,410
44	Net Additions	Line 39				9,795	8,854	8,424	5,509	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9					(980)	(1,865)	(2,707)	(3,258)	(3,258)	(3,258)	(3,258)
46	Amortization: NRBDA	Line 42 over 10 years & Note 3				(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)
47	Closing Deferral Account Balance	Sum of Lines 43 to 46				22,258	28,747	33,921	35,338	30,695	26,053	21,410	16,767
48	Total Amortization	Line 45 + Line 46				(1,385)	(2,364)	(3,250)	(4,092)	(4,643)	(4,643)	(4,643)	(4,643)
49	Mid Year Rate Base	(Line 43 + Line 47)/2				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
50	Income Tax Expense												
51	Equity Earned Return	Line 60	-	-	-	695	981	1,206	1,333	1,270	1,092	913	735
52	Add: Amortization Expense	- Line 48	-	-	-	1,385	2,364	3,250	4,092	4,643	4,643	4,643	4,643
53	Taxable Income After Tax	Line 51 + Line 52	-	-	-	2,079	3,346	4,455	5,425	5,913	5,735	5,556	5,377
54	Taxable Income	Line 53 / (1 - Line 13)	-	-	-	2,773	4,461	5,940	7,233	7,885	7,646	7,408	7,170
55	Income Tax Expense	Line 54 x Line 13	-	-	-	693	1,115	1,485	1,808	1,971	1,912	1,852	1,792

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part C: Cost of Service (2011-2021)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part C: Cost of Service (2011-2021)

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
56	Earned Return												
57	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
58	ROE Rate %	Line 3				9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
59	Equity Ratio %	Line 7				40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59				695	981	1,206	1,333	1,270	1,092	913	735
61	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
62	Short Term Debt Rate %	Line 4				3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8				6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63				44	61	76	84	80	68	57	46
65	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
66	Long Term Debt Rate %	Line 5				6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
67	Long Term Debt Ratio %	Line 9				53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67				640	905	1,112	1,229	1,171	1,007	842	677
69	Total Debt Component	Line 64 + Line 68				684	966	1,187	1,312	1,251	1,075	899	723
70	Total Earned Return	Line 60 + Line 69				1,379	1,948	2,393	2,645	2,521	2,167	1,812	1,458
71	Annual Cost of Service Impact of NGT Incentive Program												
72	Amortization Expense	- Line 48	-	-	-	1,385	2,364	3,250	4,092	4,643	4,643	4,643	4,643
73	Income Tax Expense	Line 55	-	-	-	693	1,115	1,485	1,808	1,971	1,912	1,852	1,792
74	Earned Return	Line 70	-	-	-	1,379	1,948	2,393	2,645	2,521	2,167	1,812	1,458
75	Upgrade LNG Capital COS	Note 12		-	-	-	-	-	571	8,125	8,870	9,769	10,857
76	Total Cost of Service	Sum of Lines 72 to 75	-	-	-	3,456	5,427	7,128	9,116	17,260	17,591	18,076	18,750

77 Note:
78 1: This appendix, Financial Assumptions, Section 4
79 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014
80 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014
81 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013
82 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9
83 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)
84 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38
85 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.847 Million, 2015 onwards previous year Line 47
86 9: Amortization of new additions in following year over 10 years
87 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million
88 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013
89 12: Liquefaction and Storage capital added to meet increasing LNG demand, please see financial assumption, section 9 of this appendix for further detail

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part A: Cost of Service (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part A: Cost of Service (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Key Assumptions	-									
2	Rates										
3	ROE %	BCUC Order No. G-44-12	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
4	STD Rate %	BCUC Order No. G-44-12	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate %	BCUC Order No. G-44-12	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
6	Capital Structure		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	Equity %	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
9	LTD %	BCUC Order No. G-44-12	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base %	Note 5	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
12	WACC %	Note 6	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%
13	Tax Rate %		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1	-	-	-	-	-	-	-	-	-
15	*Prior Vehicle Incentives*	Note 10	-	-	-	-	-	-	-	-	-
16	Vehicle & Marine		-	-	-	-	-	-	-	-	-
17	Maintenance Upgrades & Safety		-	-	-	-	-	-	-	-	-
18	Admin, Marketing, Train, Education		-	-	-	-	-	-	-	-	-
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	-	-	-	-	-	-	-	-	-
20	*Incentive Payouts (Cash Basis)*	Note 1									
21	*Prior Vehicle Incentives*		-	-	-	-	-	-	-	-	-
22	Vehicle & Marine	Note 1	-	-	-	-	-	-	-	-	-
23	Maintenance Upgrades & Safety	Note 1	-	-	-	-	-	-	-	-	-
24	Admin, Marketing, Train, Education	Note 1	-	-	-	-	-	-	-	-	-
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	-	-	-	-	-	-	-	-	-

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part B: Cost of Service (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part B: Cost of Service (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Non Rate Base Deferral Account (NRBDA) Calculation										
27	Gross Additions	Line 25 (2011-2013)	-	-	-	-	-	-	-	-	-
28	Tax	- Line 27 x Line 13	-	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	-	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	-	-	-	-	-	-	-	-
31	Net Additions	Line 29	-	-	-	-	-	-	-	-	-
32	Incremental Margins pre 2014	Note 7	-	-	-	-	-	-	-	-	-
33	AFUDC on Deferral Account pre 2014	Note 4, 11	-	-	-	-	-	-	-	-	-
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	-	-	-	-	-	-	-	-	-
35	Rate Base Deferral Account Calculation										
36	Amortization Period (Years)										
37	Gross Additions	Line 25 (2014+)	-	-	-	-	-	-	-	-	-
38	Tax	- Line 37 x Line 13	-	-	-	-	-	-	-	-	
39	Net Additions	Line 37 + Line 38	-	-	-	-	-	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years	-	-	-	-	-	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2	-	-	-	-	-	-	-	-	-
42	Annual Amortization of NRBDA	Line 41/10 years	-	-	-	-	-	-	-	-	-
43	Opening Deferral Account Balance	Note 8	16,767	12,124	7,481	4,223	1,944	551	0	0	0
44	Net Additions	Line 39	-	-	-	-	-	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9	(3,258)	(3,258)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
46	Amortization: NRBDA	Line 42 over 10 years & Note 3	(1,385)	(1,385)	-	-	-	-	-	-	-
47	Closing Deferral Account Balance	Sum of Lines 43 to 46	12,124	7,481	4,223	1,944	551	0	0	0	0
48	Total Amortization	Line 45 + Line 46	(4,643)	(4,643)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
49	Mid Year Rate Base	(Line 43 + Line 47)/2	14,445	9,802	5,852	3,084	1,248	275	0	0	0
50	Income Tax Expense										
51	Equity Earned Return	Line 60	556	377	225	119	48	11	0	0	0
52	Add: Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
53	Taxable Income After Tax	Line 51 + Line 52	5,199	5,020	3,483	2,397	1,441	562	0	0	0
54	Taxable Income	Line 53 / (1 - Line 13)	6,932	6,693	4,644	3,196	1,922	749	0	0	0
55	Income Tax Expense	Line 54 x Line 13	1,733	1,673	1,161	799	480	187	0	0	0

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part C: Cost of Service (continued 2022-2030)
Market expands, additional LNG equipment (liquefaction and storage) added to meet demand
$000's, Unless Otherwise Stated

Appendix G - Scenario 1: Planned Growth - using AMALCO concepts
Schedule 3, Part C: Cost of Service (continued 2022-2030)

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
56	Earned Return										
57	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
58	ROE Rate %	Line 3	0	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
59	Equity Ratio %	Line 7	0	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59	556	377	225	119	48	11	0	0	0
61	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
62	Short Term Debt Rate %	Line 4	0	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8	0	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63	35	24	14	7	3	1	0	0	0
65	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
66	Long Term Debt Rate %	Line 5	0	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
67	Long Term Debt Ratio %	Line 9	1	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67	512	348	208	109	44	10	0	0	0
69	Total Debt Component	Line 64 + Line 68	547	371	222	117	47	10	0	0	0
70	Total Earned Return	Line 60 + Line 69	1,103	749	447	235	95	21	0	0	0
71	Annual Cost of Service Impact of NGT Incentive Program										
72	Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
73	Income Tax Expense	Line 55	1,733	1,673	1,161	799	480	187	0	0	0
74	Earned Return	Line 70	1,103	749	447	235	95	21	0	0	0
75	Upgrade LNG Capital COS	Note 12	12,175	17,676	23,460	29,888	36,745	44,437	52,776	62,230	77,137
76	Total Cost of Service	Sum of Lines 72 to 75	19,654	24,741	28,326	33,202	38,714	45,196	52,776	62,230	77,137

77 Note:
78 1: This appendix, Financial Assumptions, Section 4
79 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014
80 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014
81 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013
82 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9
83 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)
84 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38
85 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.847 Million, 2015 onwards previous year Line 47
86 9: Amortization of new additions in following year over 10 years
87 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million
88 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013
89 12: Liquefaction and Storage capital added to meet increasing LNG demand, please see financial assumption, section 9 of this appendix for further detail

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012-2021)
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (2012-2021)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, unless otherwise stated

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)	Sch 2, Line 8	178	458	917	1,416	2,032	2,882	2,882	2,882	2,882	2,882
2												
3	Discount Rate	2014 FEI After-Tax WACC	6.69%									
4	Discount Period (years)		1	2	3	4	5	6	7	8	9	10
5												
6	FEI Total Delivery Margin Projections $Millions	Note 1	575	577	744	758	774	789	805	821	837	854
7												
8	Net COS Benefit (Cost) to Existing FEI Natural Gas Customers											
9	Annual Incremental Margin from additional NGT volumes	Sch 2, Line 40, Note 2,4	538	1,284	2,701	4,113	6,061	8,838	9,015	9,195	9,379	9,567
10	Annual Incentive Funding COS	Sch 3, -Line 75	-	-	(3,456)	(5,427)	(7,128)	(8,545)	(9,135)	(8,721)	(8,307)	(7,893)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	538	1,284	(755)	(1,314)	(1,067)	293	(121)	474	1,072	1,673
12												
13	Approximate Annual FEI Delivery / (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3			0.10%	0.17%	0.14%	(0.04)%	0.01%	(0.06)%	(0.13)%	(0.20)%
14												
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	505	1,128	(622)	(1,014)	(772)	199	(77)	282	598	876
16												
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	505	1,633	1,011	(3)	(775)	(576)	(653)	(371)	228	1,104
18												
19	NPV of Net COS Benefit (Cost) 2012 to 2030 (19 Years)			25,968								

20 Note:
21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,
22 does not include any impact of the prescribed undertaking expenditures or prior incentives
23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32
24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives
25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Potential Rate Impact to Existing FEI Natural Gas Customers
Potential Rate Impact to Existing FEI Natural Gas Customers
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
Schedule 1: Summary of Costs and Benefits (continued 2022 - 2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, unless otherwise stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)	Sch 2, Line 8	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
2											
3	Discount Rate	2014 FEI After-Tax WACC									
4	Discount Period (years)		11	12	13	14	15	16	17	18	19
5											
6	FEI Total Delivery Margin Projections $Millions	Note 1	871	889	906	924	943	962	981	1,001	1,021
7											
8	Net COS Benefit (Cost) to Existing FEI Natural Gas Customers										
9	Annual Incremental Margin from additional NGT volumes	Sch 2, Line 40, Note 2,4	9,758	9,953	10,152	10,355	10,562	10,773	10,989	11,209	11,433
10	Annual Incentive Funding COS	Sch 3, -Line 75	(7,479)	(7,065)	(4,866)	(3,313)	(1,969)	(759)	(0)	(0)	(0)
11	Net Annual COS Benefit (Cost) '000$	Line 9 + Line 10	2,279	2,888	5,286	7,042	8,593	10,014	10,989	11,209	11,433
12											
13	Approximate Annual FEI Delivery / (Reduction) Increase, %	-Line 11 / (Line 6 x 1000), Note 3	(0.26)%	(0.33)%	(0.58)%	(0.76)%	(0.91)%	(1.04)%	(1.12)%	(1.12)%	(1.12)%
14											
15	Present Value of Annual Net COS Benefit (Cost)	Line 11/(1+Line 3)^(Line 4)	1,118	1,328	2,278	2,844	3,253	3,554	3,655	3,494	3,341
16											
17	NPV of Net COS Benefit (Cost) '000$	Sum Line 15 2012 to year	2,221	3,549	5,827	8,671	11,925	15,478	19,133	22,627	25,968

18

19

20 Note:

21 1: 2012, 2013 based on 2012-2013 RRA G-44-12 Compliance Filing May 1, 2012; 2014+ increase at 2%/year reflecting high level long range planning assumptions,

22 does not include any impact of the prescribed undertaking expenditures or prior incentives

23 2: 2012 & 2013 incremental margin added to non rate base deferral account in Schedule 3: Cost of Service Line 32

24 3: Cumulative FEI Delivery (Reduction) increase, FEI delivery margin does not include any impact of the prescribed undertaking expenditures or prior incentives

25 4: 2012 & 2013 includes some margin already included in the 2012/13 RRA

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part A: Benefits (2012-2021)

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part A: Benefits (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
1	Annual NG Volume (TJ)											
2	Rate 16 not included in RRA 2012/13		12	183	698	1,036	1,482	2,103	2,103	2,103	2,103	2,103
3	Rate 16 included in RRA 2012/13	Note 8	139	139								
4	Rate 23 not included in RRA 2012/13		1	1	15	27	39	55	55	55	55	55
5	Rate 23 included in RRA 2012/13	Note 8	6	6								
6	Rate 25 not included in RRA 2012/13		2	110	204	353	512	725	725	725	725	725
7	Rate 25 included in RRA 2012/13	Note 8	19	19								
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	178	458	917	1,416	2,032	2,882	2,882	2,882	2,882	2,882
9	Number of CNG Stations											
10	Rate 23		-	-	-	-	1	1	1	1	1	1
11	Rate 25		1	3	5	8	11	15	15	15	15	15
12	Number of LNG Stations		2	3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume	Note 1, 4, 10	8	378	698	1,210	1,752	2,482	2,482	2,482	2,482	2,482
14	Estimated Impact to Rate 25 Demand Volume	Note 1, 5, 11	65	65								
15	Volumetric Delivery Rates ($/GJ)	Note 2										
16	Rate 16 (Net of incremental costs) Note 3	2012 & 2013 approved	3.25	3.29	3.28	3.27	3.36	3.47	3.54	3.61	3.68	3.75
17	Rate 23	2012 & 2013 approved	2.44	2.62	2.95	3.01	3.07	3.13	3.20	3.26	3.33	3.39
18	Rate 25	2012 & 2013 approved	0.68	0.73	0.85	0.86	0.88	0.90	0.91	0.93	0.95	0.97
19	Demand Rates	Note 2										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	16.82	18.06	20.23	20.63	21.05	21.47	21.90	22.34	22.78	23.24
21	Basic & Admin Charge	Note 2, 7										
22	Rate 23 $/Month	2012 & 2013 approved	210.52	210.52	210.52	214.73	219.03	223.41	227.87	232.43	237.08	241.82
23	Rate 25 $/Month	2012 & 2013 approved	665.00	665.00	665.00	678.30	691.87	705.70	719.82	734.21	748.90	763.88
24	Rate 16 $/Month	Note 9	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part B: Benefits (2012-2021)

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part B: Benefits (2012-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Incremental Margin '000$											
27	*Delivery*											
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	37	604	2,288	3,386	4,988	7,291	7,437	7,586	7,738	7,892
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	450	456								
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	2	2	45	80	118	171	174	178	181	185
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	15	16								
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	2	81	172	305	450	650	663	676	690	703
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	13	14								
34	*Demand*											
35	Rate 25 not included in RRA 2012/13	(Line 13xLine 20x12/1000)	2	82	169	300	442	639	652	665	678	692
36	Rate 25 included in RRA 2012/13	(Line 14xLine 20x12/1000)	13	14								
37	*Basic Charges*											
38	Rate 23 + 25	Note 6	5	16	27	43	63	86	88	90	92	94
39	Rate 16		-	-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	538	1,284	2,701	4,113	6,061	8,838	9,015	9,195	9,379	9,567
41	Cumulative Incremental Margin		538	1,822	4,524	8,637	14,698	23,536	32,551	41,746	51,125	60,691

42 Note:
43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month
44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions
45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,
46 Financial Assumptions, section 8
47 4 Rate 25 demand volumes not included in RRA 2012/13 filing
48 5 Rate 25 demand volumes included in RRA 2012/13 filing
49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + (Line 11 x Line 23 x 12) /1000 x (2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25
50 7 New CNG/LNG stations results in new Rate 23/25 accounts
51 8 Volumes related to prior incentives, included in 2012/13 RRA
52 9 There are no basic or admin charges for LNG Rate 16 accounts
53 10 Line 6 / 365 x 1.25 x 1000
54 11 Line 7 / 365 x 1.25 x 1000

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part A: Benefits (continued 2022-2030)

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 2, Part A: Benefits (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Annual NG Volume (TJ)										
2	Rate 16 not included in RRA 2012/13		2,103	2,103	2,103	2,103	2,103	2,103	2,103	2,103	2,103
3	Rate 16 included in RRA 2012/13	Note 8									
4	Rate 23 not included in RRA 2012/13		55	55	55	55	55	55	55	55	55
5	Rate 23 included in RRA 2012/13	Note 8									
6	Rate 25 not included in RRA 2012/13		725	725	725	725	725	725	725	725	725
7	Rate 25 included in RRA 2012/13	Note 8									
8	Total NG Volume (TJ)	Sum of Lines 2 to 7	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882	2,882
9	Number of CNG Stations										
10	Rate 23		-	-	-	1	1	1	1	1	1
11	Rate 25		3	5	8	11	15	15	15	15	15
12	Number of LNG Stations		3	5	8	11	16	18	21	25	30
13	Estimated Impact to Rate 25 Demand Volume[1,4]	Note 1, 4, 10	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482	2,482
14	Estimated Impact to Rate 25 Demand Volume[1,5]	Note 1, 5, 11									
15	Volumetric Delivery Rates ($/GJ)	Note 2									
16	Rate 16 (Net of incremental costs) Note 3	2012 & 2013 approved	3.83	3.90	3.98	4.06	4.14	4.23	4.31	4.40	4.48
17	Rate 23	2012 & 2013 approved	3.46	3.53	3.60	3.67	3.75	3.82	3.90	3.98	4.06
18	Rate 25	2012 & 2013 approved	0.99	1.01	1.03	1.05	1.07	1.09	1.11	1.14	1.16
19	Demand Rates										
20	Rate 25 $/ Month / GJ of Daily Demand	2012 & 2013 approved	23.70	24.18	24.66	25.15	25.66	26.17	26.69	27.23	27.77
21	Basic & Admin Charge	Note 2, 7									
22	Rate 23 $/Month	2012 & 2013 approved	246.66	251.59	256.62	261.76	266.99	272.33	277.78	283.33	289.00
23	Rate 25 $/Month	2012 & 2013 approved	779.15	794.74	810.63	826.84	843.38	860.25	877.45	895.00	912.90
24	Rate 16 $/Month	Note 9									
25	Inflation Annual: Delivery/Demand/Basic	Long term planning assumptions	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts

Schedule 2, Part B: Benefits (continued 2022-2030)

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts

Schedule 2, Part B: Benefits (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Incremental Margin '000$										
27	*Delivery*										
28	Rate 16 not included in RRA 2012/13	(Line 2 x Line 16)	8,050	8,211	8,375	8,543	8,714	8,888	9,066	9,247	9,432
29	Rate 16 included in RRA 2012/13	(Line 3 x Line 16)	-	-	-	-	-	-	-	-	-
30	Rate 23 not included in RRA 2012/13	(Line 4 x Line 17)	189	193	196	200	204	208	213	217	221
31	Rate 23 included in RRA 2012/13	(Line 5 x Line 17)	-	-	-	-	-	-	-	-	-
32	Rate 25 not included in RRA 2012/13	(Line 6 x Line 18)	717	732	746	761	777	792	808	824	841
33	Rate 25 included in RRA 2012/13	(Line 7 x Line 18)	-	-	-	-	-	-	-	-	-
34	*Demand*										
35	Rate 25 not included in RRA 2012/13	(Line 13xLine 20x12/1000)	706	720	734	749	764	779	795	811	827
36	Rate 25 included in RRA 2012/13	(Line 14xLine 20x12/1000)	-	-	-	-	-	-	-	-	-
37	*Basic Charges*										
38	Rate 23 + 25	Note 6	95	97	99	101	103	105	108	110	112
39	Rate 16		-	-	-	-	-	-	-	-	-
40	Total Incremental Margin	Sum of Lines 28 to 39	9,758	9,953	10,152	10,355	10,562	10,773	10,989	11,209	11,433
41	Cumulative Incremental Margin		70,449	80,402	90,554	100,910	111,472	122,245	133,234	144,443	155,876

42 Note:

43 1 Compression load is assumed to be consistent; therefore, the peak will not change in a winter month

44 2 Existing delivery / demand / basic & admin charges are approved 2012 and 2013 charges, 2014+ increase at 2% per year reflecting high level long range planning assumptions

45 3 Rate 16 reflects delivery rate minus incremental cost of LNG (incremental O&M / incremental volume sold into the LNG market), further detail included in this appendix,

46 Financial Assumptions, section 8

47 4 Rate 25 demand volumes not included in RRA 2012/13 filing

48 5 Rate 25 demand volumes included in RRA 2012/13 filing

49 6 (Line 10 x Line 22 x 12) /1000 x (2/3) + (Line 11 x Line 23 x 12) /1000 x (2/3); Basic charges reduce by 1/3 to reflect that some existing accounts are already on R23/25

50 7 New CNG/LNG stations results in new Rate 23/25 accounts

51 8 Volumes related to prior incentives, included in 2012/13 RRA

52 9 There are no basic or admin charges for LNG Rate 16 accounts

53 10 Line 6 / 365 x 1.25 x 1000

54 11 Line 7 / 365 x 1.25 x 1000

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts

Schedule 3, Part A: Cost of Service (2011-2021)
Schedule 3, Part A: Cost of Service (2011-2021)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1	Key Assumptions												
2	Rates												
3	ROE %	BCUC Order No. G-44-12	9.50%	9.50%	9.50%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
4	STD Rate	BCUC Order No. G-44-12	4.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate	BCUC Order No. G-44-12	6.95%	6.85%	6.87%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
6	Capital Structure												
7	Equity	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	1.63%	1.93%	3.03%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
9	LTD %	BCUC Order No. G-44-12	58.37%	58.07%	56.97%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base	Note 5	7.93%	7.83%	7.82%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
12	WACC	Note 6	6.84%	6.82%	6.81%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%
13	Tax Rate		26.50%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1											
15	Prior Vehicle Incentives	Note 10	5,573										
16	Vehicle & Marine		-	7,843	11,479	10,404	9,807	9,794	-				
17	Maintenance Upgrades & Safety		-	200	950	950	950	950	-				
18	Admin, Marketing, Train, Education		-	300	1,000	900	600	300	-				
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	5,573	8,343	13,429	12,254	11,357	11,044	-				
20	Incentive Payouts (Cash Basis)	Note 1											
21	Prior Vehicle Incentives		5,573										
22	Vehicle & Marine	Note 1	-	1,961	8,752	11,210	10,255	9,804	7,345				
23	Maintenance Upgrades & Safety	Note 1		50	922	950	950	1,128	-				
24	Admin, Marketing, Train, Education	Note 1		300	1,000	900	600	300	-				
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	5,573	2,311	10,674	13,060	11,805	11,232	7,345				

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part B: Cost of Service (2012-2021)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part B: Cost of Service (2012-2021)

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
26	Non Rate Base Deferral Account (NRBDA) Calculation												
27	Gross Additions	Line 25 (2011-2013)	5,573	2,311	10,674								
28	Tax	- Line 27 x Line 13	(1,477)	(578)	(2,668)	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	4,097	1,733	8,005	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	4,097	5,851								
31	Net Additions	Line 29	4,097	1,733	8,005								
32	Incremental Margins pre 2014	Note 7		(36)	(588)								
33	AFUDC on Deferral Account pre 2014	Note 4 , 11	-	58	579								
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	4,097	5,851	13,847								
35	Rate Base Deferral Account Calculation												
36	Amortization Period (Years)		10										
37	Gross Additions	Line 25 (2014+)				13,060	11,805	11,232	7,345	-	-	-	-
38	Tax	- Line 37 x Line 13				(3,265)	(2,951)	(2,808)	(1,836)	-	-	-	-
39	Net Additions	Line 37 + Line 38				9,795	8,854	8,424	5,509	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years				980	885	842	551	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2				13,847							
42	Annual Amortization of NRBDA	Line 41/10 years				1,385							
43	Opening Deferral Account Balance	Note 8				13,847	22,258	28,747	33,921	35,338	30,695	26,053	21,410
44	Net Additions	Line 39				9,795	8,854	8,424	5,509	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9					(980)	(1,865)	(2,707)	(3,258)	(3,258)	(3,258)	(3,258)
46	Amortization: NRBDA	Line 42 over 10 years & Note 3				(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)	(1,385)
47	Closing Deferral Account Balance	Sum of Lines 43 to 46				22,258	28,747	33,921	35,338	30,695	26,053	21,410	16,767
48	Total Amortization	Line 45 + Line 46				(1,385)	(2,364)	(3,250)	(4,092)	(4,643)	(4,643)	(4,643)	(4,643)
49	Mid Year Rate Base	(Line 43 + Line 47)/2				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
50	Income Tax Expense												
51	Equity Earned Return	Line 60	-	-	-	695	981	1,206	1,333	1,270	1,092	913	735
52	Add: Amortization Expense	- Line 48	-	-	-	1,385	2,364	3,250	4,092	4,643	4,643	4,643	4,643
53	Taxable Income After Tax	Line 51 + Line 52	-	-	-	2,079	3,346	4,455	5,425	5,913	5,735	5,556	5,377
54	Taxable Income	Line 53 / (1 - Line 13)	-	-	-	2,773	4,461	5,940	7,233	7,885	7,646	7,408	7,170
55	Income Tax Expense	Line 54 x Line 13	-	-	-	693	1,115	1,485	1,808	1,971	1,912	1,852	1,792

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part C: Cost of Service (2012-2021)
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part C: Cost of Service (2012-2021)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
56	Earned Return												
57	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
58	ROE Rate %	Line 3				9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
59	Equity Ratio %	Line 7				40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59				695	981	1,206	1,333	1,270	1,092	913	735
61	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
62	Short Term Debt Rate %	Line 4				3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8				6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63				44	61	76	84	80	68	57	46
65	Total Rate Base	Line 49				18,052	25,502	31,334	34,630	33,017	28,374	23,731	19,088
66	Long Term Debt Rate %	Line 5				6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
67	Long Term Debt Ratio %	Line 9				53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67				640	905	1,112	1,229	1,171	1,007	842	677
69	Total Debt Component	Line 64 + Line 68				684	966	1,187	1,312	1,251	1,075	899	723
70	Total Earned Return	Line 60 + Line 69				1,379	1,948	2,393	2,645	2,521	2,167	1,812	1,458
71	Annual Cost of Service Impact of NGT Incentive Program												
72	Amortization Expense	- Line 48	-	-	-	1,385	2,364	3,250	4,092	4,643	4,643	4,643	4,643
73	Income Tax Expense	Line 55	-	-	-	693	1,115	1,485	1,808	1,971	1,912	1,852	1,792
74	Earned Return	Line 70	-	-	-	1,379	1,948	2,393	2,645	2,521	2,167	1,812	1,458
75	Total Cost of Service	Sum of Lines 72 to 74	-	-	-	3,456	5,427	7,128	8,545	9,135	8,721	8,307	7,893

76 Note:
77 1: This appendix, Financial Assumptions, Section 4
78 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014
79 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014
80 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013
81 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9
82 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)
83 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38
84 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.847 Million, 2015 onwards previous year line 47
85 9: Amortization of new additions in following year over 10 years
86 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million
87 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part A: Cost of Service (continued 2022-2030)
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part A: Cost of Service (continued 2022-2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	Key Assumptions	-									
2	Rates										
3	ROE %	BCUC Order No. G-44-12	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
4	STD Rate	BCUC Order No. G-44-12	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
5	LTD Rate	BCUC Order No. G-44-12	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
6	Capital Structure		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7	Equity	BCUC Order No. G-44-12	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
8	STD %	BCUC Order No. G-44-12	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
9	LTD %	BCUC Order No. G-44-12	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
10	Total %		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
11	Return on Rate Base	Note 5	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
12	WACC	Note 6	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%	6.69%
13	Tax Rate		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
14	Incentive Award Schedule	Note 1									
15	*Prior Vehicle Incentives*	Note 10	-	-	-	-	-	-	-	-	-
16	Vehicle & Marine		-	-	-	-	-	-	-	-	-
17	Maintenance Upgrades & Safety		-	-	-	-	-	-	-	-	-
18	Admin, Marketing, Train, Education		-	-	-	-	-	-	-	-	-
19	Total Incentive Awards ($62000)	Sum of Lines 15 to 18	-	-	-	-	-	-	-	-	-
20	*Incentive Payouts (Cash Basis)*	Note 1									
21	*Prior Vehicle Incentives*		-	-	-	-	-	-	-	-	-
22	Vehicle & Marine	Note 1	-	-	-	-	-	-	-	-	-
23	Maintenance Upgrades & Safety	Note 1	-	-	-	-	-	-	-	-	-
24	Admin, Marketing, Train, Education	Note 1	-	-	-	-	-	-	-	-	-
25	Total Incentive Payouts (Cash Basis)	Sum of Lines 21 to 24	-	-	-	-	-	-	-	-	-

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part B: Cost of Service (continued 2022-2030)
Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts
Schedule 3, Part B: Cost of Service (continued 2022-2030)
Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained
$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
26	Non Rate Base Deferral Account (NRBDA)	Calculation									
27	Gross Additions	Line 25 (2011-2013)	-	-	-	-	-	-	-	-	-
28	Tax	- Line 27 x Line 13	-	-	-	-	-	-	-	-	-
29	Net Additions	Line 27 + Line 28	-	-	-	-	-	-	-	-	-
30	Opening Deferral Account Balance	Previous Year, Line 34	-	-	-	-	-	-	-	-	-
31	Net Additions	Line 29	-	-	-	-	-	-	-	-	-
32	Incremental Margins pre 2014	Note 7	-	-	-	-	-	-	-	-	-
33	AFUDC on Deferral Account pre 2014	Note 4 , 11	-	-	-	-	-	-	-	-	-
34	Closing Deferral Account Balance	Sum of Lines 30 to 33	-	-	-	-	-	-	-	-	-
35	Rate Base Deferral Account Calculation										
36	Amortization Period (Years)										
37	Gross Additions	Line 25 (2014+)	-	-	-	-	-	-	-	-	-
38	Tax	- Line 37 x Line 13	-	-	-	-	-	-	-	-	-
39	Net Additions	Line 37 + Line 38	-	-	-	-	-	-	-	-	-
40	Annual Amortization of Net Addition	Line 39/10 years	-	-	-	-	-	-	-	-	-
41	Add NRBDA	Line 34, 2013 Closing & Note 2	-	-	-	-	-	-	-	-	-
42	Annual Amortization of NRBDA	Line 41/10 years	-	-	-	-	-	-	-	-	-
43	Opening Deferral Account Balance	Note 8	16,767	12,124	7,481	4,223	1,944	551	0	0	0
44	Net Additions	Line 39	-	-	-	-	-	-	-	-	-
45	Amortization: Net Additions	Sum of Line 40 & Note 9	(3,258)	(3,258)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
46	Amortization: NRBDA	Line 42 over 10 years & Note 3	(1,385)	(1,385)	-	-	-	-	-	-	-
47	Closing Deferral Account Balance	Sum of Lines 43 to 46	12,124	7,481	4,223	1,944	551	0	0	0	0
48	Total Amortization	Line 45 + Line 46	(4,643)	(4,643)	(3,258)	(2,279)	(1,393)	(551)	-	-	-
49	Mid Year Rate Base	(Line 43 + Line 47)/2	14,445	9,802	5,852	3,084	1,248	275	0	0	0
50	Income Tax Expense										
51	Equity Earned Return	Line 60	556	377	225	119	48	11	0	0	0
52	Add: Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
53	Taxable Income After Tax	Line 51 + Line 52	5,199	5,020	3,483	2,397	1,441	562	0	0	0
54	Taxable Income	Line 53 / (1 - Line 13)	6,932	6,693	4,644	3,196	1,922	749	0	0	0
55	Income Tax Expense	Line 54 x Line 13	1,733	1,673	1,161	799	480	187	0	0	0

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts

Appendix H - Scenario 2: GGRR Load Growth Only - using AMALCO concepts

Schedule 3, Part C: Cost of Service (continued 2022-2030)

Schedule 3, Part C: Cost of Service (continued 2022-2030)

Market does not expand after incentives, NGV vehicles replaced at end of product cycle and volumes maintained

$000's, Unless Otherwise Stated

		Reference	2022	2023	2024	2025	2026	2027	2028	2029	2030
56	Earned Return										
57	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
58	ROE Rate %	Line 3	0	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%	9.62%
59	Equity Ratio %	Line 7	0	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
60	Equity Return	Line 57 x Line 58 x Line 59	556	377	225	119	48	11	0	0	0
61	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
62	Short Term Debt Rate %	Line 4	0	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
63	Short Term Debt Ratio %	Line 8	0	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%	6.89%
64	Short Term Debt Component	Line 61 x Line 62 x Line 63	35	24	14	7	3	1	0	0	0
65	Total Rate Base	Line 49	14,445	9,802	5,852	3,084	1,248	275	0	0	0
66	Long Term Debt Rate %	Line 5	0	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%	6.68%
67	Long Term Debt Ratio %	Line 9	1	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%	53.11%
68	Long Term Debt Component	Line 65 x Line 66 x Line 67	512	348	208	109	44	10	0	0	0
69	Total Debt Component	Line 64 + Line 68	547	371	222	117	47	10	0	0	0
70	Total Earned Return	Line 60 + Line 69	1,103	749	447	235	95	21	0	0	0
71	Annual Cost of Service Impact of NGT Incentive Program										
72	Amortization Expense	- Line 48	4,643	4,643	3,258	2,279	1,393	551	-	-	-
73	Income Tax Expense	Line 55	1,733	1,673	1,161	799	480	187	0	0	0
74	Earned Return	Line 70	1,103	749	447	235	95	21	0	0	0
75	Total Cost of Service	Sum of Lines 72 to 74	7,479	7,065	4,866	3,313	1,969	759	0	0	0

76 Note:

77 1: This appendix, Financial Assumptions, Section 4

78 2: Non rate base deferral account is transferred to the rate base deferral account at the start of 2014

79 3: Non rate base deferral account transferred to rate base deferral account in 2014 and amortized over 10 years starting in 2014

80 4: AFUDC calculated on prior incentives added to non rate base deferral account from the date (forecasted Oct 2012) of the first vehicle and marine incentive payment to end of 2013

81 5: Line 3 x Line 7 + Line 4 x Line 8 + Line 5 x Line 9

82 6: Line 3 x Line 7 + (Line 4 x Line 8 + Line 5 x Line 9) x (1 - Line 13)

83 7: Exclude volumes / margin already included in RRA 2012/2013; Schedule 2 Benefits: Line 28+ Line 30 + Line 32 + Line 35 + Line 38

84 8: 2014 Opening rate base deferral account equals 2013 closing non rate base deferral account of $13.847 Million, 2015 onwards previous year line 47

85 9: Amortization of new additions in following year over 10 years

86 10: Prior incentive spending in 2011 includes 2010 amounts, totals $5.573 million

87 11: AFUDC calculated on incentives added to the non rate base deferral account from Aug 2012 to the end of 2013

3.7 Would Mt. Hayes be used as a source for on island trucking and or for the marine services?

Response:

Yes. FEI plans to draw LNG for these applications from Mt. Hayes as soon as regulatory approval for this is achieved through amendments to Rate Schedule 16 and a truck loading capability can be added to the Mt. Hayes facility.

4. Exhibit B-1, Page 18

5.2.1 OVERVIEW

Prescribed undertaking 1 is made up of grants or zero interest loans to eligible trucks and buses, expenditures on administration, marketing, training and education, and grants to implement safety practices or to improve maintenance facilities. FEI will include a portion of the regulatory costs of this Application as an administrative expense of prescribed undertaking 1. Total expenditures for Prescribed Undertaking 1 in the undertaking period are not to exceed $62 million.

4.1 Please provide the anticipated breakdown of the amounts FEI expects to offer in grants and in loans, over the timeframe for the regulations year by year.

Response:

At this time, FEI plans only to offer grants to applications under Prescribed Undertaking 1. Please refer to "Total Incentive Award Schedule" in page 3 of Appendix G and page 3 of Appendix H for the current planned incentive award schedule. This is just a plan and the actuals may vary depending on the number of applications received and finally awarded in that particular year. FEI is currently midway through the evaluation process of the applicants in this round of funding and will make the list of successful applicant's with the award details public once the awards are finalized.

5. Exhibit B-1, Page 13

> The Regulation permits a public utility to spend up to $62 million, in total, prior to April 1, 2017 for this prescribed undertaking. Included in this $62 million are a number of subcategories, as summarized in Table 4-1. The first subcategory of disbursements during the program period is for marine vehicles, and is not to exceed $11 million. In addition, there is a subcategory of expenditures that include administration, marketing, training and education that are not to exceed $3.1 million in the undertaking period. A third subcategory of grants to implement safety practices or to improve maintenance facilities required to satisfy safety guidelines for the operation and maintenance of natural gas-fuelled vehicles is also available and capped at $4 million in the undertaking period. However, if the funding for these subcategories has not been totally applied, then any amounts remaining can be redirected to additional grants or zero interest loans for "specified vehicles" subject to the overall cap remaining at $62 million.

5.1 Please advise whether or not FEI could and or would exceed the $62 million investment in order to advance the adoption of the NGT faster than is shown in this plan over 5 years.

Response:

Under the present GGRR regulation, FEI is limited to $62 million investment in vehicle incentives for qualifying as prescribed undertakings. FEI would not undertake expenditures beyond that amount without the comfort of a new or amended regulation or prior Commission approval.

5.2 If so please advise how this would be done.

Response:

Please refer to the response to CEC IR 1.5.1.

5.3 If not please advise why not.

Response:

Please refer to the response to CEC IR 1.5.1.

6. Exhibit B-1, Page 18

> FEI has considered alternative accounting and rate recovery methodologies that recover costs from all non-bypass customers, and concluded that the appropriate treatment for all expenditures under this prescribed undertaking is to include them in a rate base deferral account and amortize the expenditures in delivery rates of all non-bypass customers over a ten-year period. This methodology was approved and utilized for the EEC expenditures, and remains appropriate for NGT Incentive Program expenditures. While the rate base deferral and ten-year amortization are the key principles, there are several circumstances that require minor or temporary adjustments to this treatment; these are discussed below.

6.1 Please provide a full description of the alternatives considered.

Response:

In the evaluation of alternatives for accounting and rate recovery methodologies for the NGT Incentive Program, FEI also considered: (A) the annual expense and recovery of incentive costs; and, (B) a rate base deferral account with rate rider recovery. These two alternatives to the chosen approach are discussed further below:

A. Annual Expense and Recovery

With this alternative, the annual incentives would be forecast as an expense in the revenue requirements and recovered completely through the delivery rates for that year. This approach would result in a greater delivery rate increase in the first year and a greater delivery rate decrease following the final year of the NGT Incentives program, all else equal and in the absence of a variance account, this approach does not provide a mechanism for ensuring that only the actual NGT incentives are recovered. Further, this approach does not consider the duration of timing of the benefits associated with the NGT Incentive Program. Finally, due to the timing of the Regulation and the 2012-2013 RRA, this approach would require the use of a deferral account at a minimum for 2012 and 2013 and would result in the recovery of three years of NGT incentives in 2014 (i.e. the first year that the delivery rates were reset to recover the incentive costs).

B. Rate Base Deferral Account, Rate Rider Recovery

With this alternative, the annual incentives would be captured in a rate base deferral account and recovered from non-bypass customers through a delivery rate rider. Each year the rate rider would be reset to reflect the before tax opening balance of the account and the forecast annual additions to the account, recovered over a ten-year period. Under this approach, the same net impact to customers is achieved as with recovery through the cost of service and delivery rates; however, there is added administration with the use of a rate rider. Further, FEI typically reserves the use of rate riders for short-term extraordinary items or ongoing variance accounts such as the revenue stabilization adjustment mechanism (RSAM).

In consideration of these two alternatives, FEI has proposed the use of the rate base deferral account with recovery through the delivery rates of non-bypass customers over a ten-year period. This approach meets the ratemaking and accounting objective of matching costs and benefits and in turn best achieves the concept of intergenerational equity. Further, the proposed approach also avoids the rate volatility that would occur with an expensing approach.

A variant of FEI's applied-for approach is to employ the same approach except using a different amortization period. FEI considered a five-year amortization period as an alternative and although it provides some of the same benefits as the proposed ten-year amortization period FEI judged that a five-year amortization period did not meet the goals of matching costs and benefits, intergenerational equity and avoiding rate volatility as well as the ten-year amortization period does. Please refer to the response to BCUC IR 1.10.1 for an analysis of the impacts of the five-year amortization period.

7. Exhibit B-1, Page 19

Other significant benefits to non-bypass customers include a reduction in GHG emissions and air contaminants. GHG emissions from the transportation sector largely originate in the Lower Mainland and nearby regions, thus the cost recovery of Prescribed Undertaking 1 from non-bypass natural gas customers (within FEI) is reasonable. FEI's service territory includes the Lower Mainland and represents approximately 850,000 customers.

FEI has received suggestions from stakeholders in the GGRR development process that the incentives should be recovered from the parties that receive them, out of their fuel cost savings. FEI believes that requiring recovery of incentives from only the parties that receive them would be an obstacle to carrying out the prescribed undertaking as this treatment would, in FEI's estimation, reduce interest in the program and limit the ability to attract fleets to natural gas as a transportation fuel.

This is evidenced by the uptake in the purchase of natural gas transportation only once incentive funding was provided to companies such as Vedder and Waste Management. Even though interest rates and commodity costs are at their lowest levels in many years, there has been little interest in the purchase of natural gas fueled vehicles, regardless of the associated fuel savings. These vehicles were purchased only once incentive funding was granted.

7.1 Please provide the estimated end customer savings from their fleet conversions over the analysis timeframe with the quantitative analysis done yearly to match Appendix G Schedule 1.

Response:

FEI's response to BCUC IR 1.11.1 shows an extensive analysis of the fuel savings benefit per NGV for the average end customer for each year under the GGRR (2012-2016). These results also show the fuel savings benefit over the vehicle life for each category defined in the GGRR.

7.2 Please provide the matching estimated GHG savings from the fleet conversions over the analysis timeframe with the quantitative analysis done yearly to match Appendix G schedule 1.

Response:

Please refer to the response to BCSEA IR 1.1.2.

7.3 Please provide an analysis of the reduction in other key air pollutants from the transformation to NGT, and provide any information FEI has with respect to the potential health improvement effects from the conversions to NGT.

Response:

In addition to GHG emission reductions (CO2e), the transformation to NGT will reduce air pollutants such as NOx, SOx and other Particulate Matter. FEI has used data from the GHGenius version 4.01 to quantify these reductions. The table below summarizes the percentage reduction in air pollutants that would occur from transitioning diesel fueled vehicles to NGT vehicles.

Reduction in Air Pollutants vs Diesel Fuel	CNG	LNG
NOx	-20.9%	-30.9%
SOx	-70.2%	-73.7%
Other Particulate Matter (PM)	-46.4%	-50.2%

A transition to NGT vehicles from diesel fuel also results in fewer carcinogens from diesel engine exhaust that are known to cause illnesses such as lung cancer. A recent report from the International Agency for Research on Cancer classified diesel engine exhaust as a carcinogen.[2]

[2] http://www.abc.net.au/news/2012-06-13/diesel-fumes-carcinogenic/4068414

8. Exhibit B-1, Page 19

> Requiring recipients to repay their incentives through rates would, in effect, turn a grant into a loan and eliminate the permissible option in the prescribed undertaking of providing grants. Requiring the recipients to repay their incentives would also be contrary to established practices in other areas such as with the FEU's EEC programs. For example, a residential customer that receives an EEC incentive to purchase more efficient equipment to reduce their gas use is not required to repay the incentive. If EEC programs were structured that way there would be little

8.1 Please confirm that EEC programs do not have a pay-back to existing customers but rather cost existing customers in terms of reduced throughput on the system and therefore very different than the proposed NGT programs.

Response:

FEI interprets the term "pay-back" to mean that from a delivery rate perspective the cost of the program is offset by incremental revenues from the program. In that regard, FEI does expect that the delivery rate benefit of the increased throughput in natural gas due to the NGT Incentives program will provide a net benefit to natural gas customers (or pay-back) when the costs of the program are considered.

The purpose of demand side management (DSM) and EEC programs is to achieve energy conservation and efficiency in BC which has been a strong policy focus of the government for a number of years. DSM programs generally lead to a reduction in demand or throughput, all else equal. As such, from a delivery rate perspective, the decreased throughput from DSM programs and the costs of the programs both put upward pressure on delivery rates[3]. However, there are social, environmental and economic benefits of the programs that are evaluated and considered in the adoption of these programs. Further, the EEC Annual Reports have extensively reviewed past EEC programs and the overall portfolio has been cost-effective. Therefore, while the EEC programs may not provide incremental delivery margin recoveries, they do provide other benefits to natural gas customers in the province and serve mandated provincial efficiency and conservation objectives.

[3] Whether demand reductions provide an economic payback is also dependent on the marginal cost of another unit of energy. In cases where marginal costs of serving additional demand are higher than the cost of the DSM program, such as is the case in the electricity sector in BC there will be an economic payback associated with demand reductions. In the natural gas sector the marginal or avoided costs of delivering another unit of gas are lower than the cost of the DSM programs so delivery rates will rise from DSM programs.

9. Exhibit B-1, Page 20

5.2.4 AMORTIZATION PERIOD

FEI considers a ten year amortization period to be an appropriate time frame for amortization as this approximates the expected life of the CNG/LNG vehicles as well as the period over which the benefits of the program are experienced[20]. This meets the ratemaking and accounting objective of matching costs and benefits and in turn achieves the concept of intergenerational equity. The costs of the programs should be matched against the benefits that are derived which would not be the case if the costs of the program are simply expensed in a single year. In that scenario, current customers would bear the expense and future customers would reap the benefits. In addition to matching costs and benefits, the proposed approach also avoids the rate volatility that would occur with an expensing approach.

9.1 Please advise if the FEI expect that after 10 years the customers who had implemented a conversion would be likely to convert back to gasoline and or diesel.

Response:

FEI believes that customers who use NGVs in their operations will continue to utilize NGV (through new orders) after the initial period. FEI believes this because all fleets that have been converted to NGV to date (Vedder, Waste Management, Surrey, and the Kelowna School District) are all satisfied with the results achieved to date.

In addition the fuel price spread between diesel and natural gas is forecast to be maintained, so the economic business case should support the continued use of NGVs.

Please refer to the response to BCUC IR 1.19.7 for a more detailed explanation complete with source references and an explanation of why incentives are required for initial purchases but are not required for follow on purchases.

9.2 Please advise whether or not the FEI are working with the Ministry on any kind of codes and standards for heavy duty transportation or marine transport and if not please explain why not?

Response:

FEI is not working with the Ministry on codes or standards for heavy duty transportation or marine transport.

Codes and standards for the heavy duty transportation industry are under the administration of Transport Canada. This agency also promotes efficient marine transportation and safe, secure and sustainable marine practices including marine infrastructure. FEI is working with industry partners such as the Canadian Natural Gas Vehicle Alliance and others on codes and standards, as well as a study on adoption of natural gas in the marine sector. With regard to fueling stations FEI is working with organizations such as the BC Safety Authority to establish appropriate standards for natural gas vehicle fueling, particularly for LNG which is a cryogenic fuel and a new technology. The goal of all this work is to provide a smooth transition to the adoption of natural gas in the target market sectors and support the long term beneficial use of natural gas in transportation.

10. Exhibit B-1, Page 28

> The policy rationale supporting the 2010-2011 NGV Incentives is consistent with the policy rationale underpinning Prescribed Undertaking 1. As a result, the order sought by FEI in respect of the 2010-2011 NGV Incentives (that they were prudently incurred) does not extend to seeking approval for future expenditures of a similar nature outside the scope of Prescribed Undertaking 1. In the event that the Commission approves the recovery of some or all of the 2010-2011 NGV Incentives, FEI will commit to reduce the amount of incentives dispensed under Prescribed Undertaking 1 by the amount of the 2010-2011 NGV Incentives approved for recovery. Therefore, the total amount of vehicle incentives that can be dispensed in 2012 and onwards as a result of this Application (inclusive of the amount of 2010-2011 NGV Incentives if approved) will not exceed the Prescribed Undertaking 1 maximum of $62 million.

10.1 Please explain why FEI would reduce its future ability to offer incentives by deducting the past expenditures from the future ability to provide funding.

Response:

FEI has made this proposal as a practical means to assist in the timely resolution of the prudency review of these prior incentives. FEI is of the view that both the past expenditures and the expenditures under the GGRR provide real benefits to customers. However, FEI recognizes that its view may not be shared by all stakeholders. FEI made the proposal to address what we perceived as a concern on the part of some stakeholders that the approval of the past expenditures might increase the overall expenditures on NGVs. Should the Commission conclude that the full GGRR prescribed amount should be spent in addition to allowing the past expenditures, FEI would give further consideration to that approach.

10.2 Please show the impact on the present value benefits to existing customers if the anticipated benefits of $5.6 million are removed from the financial analysis throughout the analysis period.

Response:

Please refer to the responses to BCUC IRs 1.17.5 and 1.19.8.

11. Exhibit B-1, Page 31

Table 7-1: Commercial NGV Demonstration Program – 2010/2011 Incentives Committed26

Customer Receiving NGV Incentive	Incentive Amount Committed ($)	Date of Agreement for EEC Incentive Funding (MM/DD/YYYY)	Estimated Fuel Savings to Customer ($)	Customer Estimated Avoided Diesel (L)	Customer Estimated GHG Reductions (tonnes)	Estimated Revenue to FortisBC Energy ($)	Total Resource Cost (TRC) Test Ratio
City of Surrey	$ 26,700	9/15/2010	$ 18,566	34,000	13	$ 5,611	1.7
Kelowna School District	$ 363,286	3/17/2011	$ 17,587	95,436	120	$ 21,888	1.1
Waste Management	$ 803,560	12/3/2010	$ 202,651	468,000	214	$ 38,728	1.4
Vedder Transport	$ 4,393,300	12/10/2010	$ 1,877,989	3,582,850	3,754	$ 548,460	1.4
Total	$ 5,586,846		$ 2,116,793	4,180,286	4,100	$ 614,687	

Source: 2011 NGV Incentive Review, Exhibit B-1, BCUC IR 1.7.2 (Totals added)

11.1 Do all of the investments made remain used and useful to the end use customers and to the existing natural gas ratepayers.

Response:

Yes, all investments made by the Utility remain used and useful. To clarify, the investment by the Utility is the incentives granted to assist with vehicle purchases. The vehicles themselves are not being added to rate base. Rather, the incentives are included in a rate base deferral account and the costs are amortized over a fixed period. An incentive is used and useful throughout its amortization period as it has resulted in the purchase of a vehicle, its intended utility purpose.

Please refer to the response to BCUC IR 1.5.1 for the expected vehicle measure life for each customer.

11.2 Please update the table with current actual results.

Response:

The following table contains updated actual results:

Customer Receiving NGV Incentive	Incentive Amount Committed ($)	Date of Agreement for EEC Incentive Funding (MM/DD/YYYY)	Estimated Fuel Savings to Customer ($ per year)	Customer Estimated Avoided Diesel (L per year)	Customer Estimated GHG Reductions (tonnes per year)	Estimated Revenue to FortisBC Energy ($ per year)	Total Resource Cost (TRC) Test Ratio
City of Surrey	$ 13,350	9/15/2010	$ 19,889	29,751	10	$ 4,448	2.1
Kelowna School District	$ 363,286	3/17/2011	$ 17,587	116,415	132	$ 17,406	1.3
Waste Management	$ 803,560	12/3/2010	$ 562,320	776,100	317	$ 39,679	1.8
Vedder Transport	$ 4,393,300	12/10/2010	$ 2,595,060	4,656,600	5,604	$ 729,000	1.6
Total	$ 5,573,496		$ 3,194,856	5,578,866	6,063	$ 790,534	

These calculations are based on the following assumptions:

- Actual amount paid to City of Surrey was $13,350 (as stated at page 31 of the Application);
- Fuel savings estimates based on current natural gas delivery rates and diesel price estimates;
- Actual volumes (GJ and diesel litres) described at page 43 of the Application;
- GHG emission reductions based on GHGenius version 4.01;
- 2012 delivery rates used to calculate Estimated Revenue to FEI; and
- No changes to the TRC test model, other than volumes (and cost input for City of Surrey).

11.3 Please provide a present value benefit analysis over future years to 2030 assuming that these end customers continue to use the NVG equipment.

Response:

A present value cost benefit analysis for this question has been provided in Appendix W of the Application. The analysis in Appendix W demonstrates that there is an NPV cost-of-service benefit from these four NGT customers of $1.229 million based on the assumptions in the question.

11.4 Please evaluate quantitatively for these customers what additional conversions they may have the ability to make within their current fleets and what the benefits of those additional conversions might add to the previously requested present value of the existing $5.6 million investment.

Response:

Phase 3 will be dealing with the $5.6 million. However, FEI has provided a brief update of each customer below.

1. The City of Surrey has already awarded a contract to convert their refuse and recycling collection vehicles to CNG. This added 52 new trucks with an estimated load of 60,000 GJ/year. (Equivalent to adding approximately 667 houses to the FEI system.)
2. The Kelowna School District operates approximately 73 buses, 13 of which are CNG buses. Potential load addition from the remaining fleet would be in the range of 20,000 GJ/yr.
3. Waste Management operates 100 vehicles from its site. Conversion of the remaining 80 vehicles to CNG could be expected to add a further 80,000 to 100,000 GJ/yr of load to the FEI system.
4. Vedder Transport operates approximately 300 tractor trailers. Assuming the same fuel consumption on these units the potential load addition ranges from 850,000 to 1,000,000 GJ/year.

The sum of these potential additions represents roughly a 6 to 7 multiple increase from the current benefit estimates in Table 7-1.

FEI notes that there may be barriers to achieving 100% share within a fleet as some vehicles do not operate regularly between fixed points that can be served with a limited fueling network. While the NGT initiative is in its early days, there is scope for additional load generation from these accounts that would represent indirect benefits of the initial funding.

11.5 Please provide the FEI current understanding of the likely future scenario for these end use customers in terms of continued use and likely possible growth up to 2030.

Response:

FEI has summarized the possible future scenarios for each customer below.

1. The City of Surrey has already moved forward with a commitment to fuel 52 new heavy duty CNG garbage trucks. There is scope for further vehicle additions (e.g. dump trucks and pickup trucks) but FEI has not quantified the potential.
2. Kelowna School District's future vehicle additions are dependent on budget allocations from the Province. No substantial vehicle additions are planned to the best of FEI's knowledge.
3. Waste Management has previously advised FEI that they plan to convert their entire fleet totalling some 100 vehicles to CNG as replacements are ordered over their 10 year replacement cycle.
4. Vedder Transport has plans to add more LNG powered vehicles. FEI is not privy to details as this is confidential Vedder information.

11.6 Please provide any information the FEI have with respect to whether or not these end use customers provide reference information for other customers considering conversions and whether or not the FEI are able to use these customer's sites and fleets as demonstration opportunities for promoting the success potential for NGT.

Response:

All four customers involved have acted as reference accounts and industry advocates for the use of NGV. All have hosted various site visits for potential adopters of NGVs.

12. Exhibit B-1, Page 37

> When FEI issued the 2010-2011 NGV Incentives, it did so in good faith and on the basis of its belief that the approved EEC framework permitted it to do so.[42] In the course of the Incentive Review proceeding, FEI provided detailed evidence and submissions regarding its position that it had approval to issue the 2010-2011 NGV Incentives. The evidence and submissions provided by FEI in the NGV Incentive Review in support of its position have been included with this Application as Appendix K. FEI's position that it had approval was supported in the Final Submissions of other parties to the proceeding, including The Ministry of Energy and Mines, BC Sustainable Energy Association ("BCSEA"), and Commercial Energy Consumers Association of BC ("CEC").
>
> BCSEA and CEC agreed with FEI's characterization of how the EEC framework was intended to operate. All three parties also stated their support of the Commercial NGV Incentive Program as being in the public interest.

12.1 Has anything changed in respect to the NGV incentives providing benefits to FEI's existing customer since the inception of the program, which would lead to a conclusion that the potential future benefits anticipated may be diminished below the expectations at the time the expenditures were made?

Response:

The results achieved from the program closely match the forecast with the exception that load additions have generally been greater than contracted and forecast. This is because the NGVs have a lower operating cost base so the fleet managers are maximizing the use of the NGV portion of the fleet versus their diesel vehicles. As well, the performance and operation of these vehicles has been successful and uninterrupted to date.

Thus, to date, there has been no change that would lead to the conclusion that future benefits may be diminished below the expectations at the time the expenditures were made.

13. Exhibit B-1, Page 39

> The 2010 LTRP reiterated the Companies' concern about declining throughput, attributable in part to declining use per customer rates, which adds to upward pressure on delivery rates and also represents a long-term stranding risk for the distribution system assets as a whole. At the time and at present, NGVs represented one of the best opportunities to mitigate the adverse delivery rate impact on existing customers flowing from this declining throughput. The addition of cost-effective NGV load on the FEI distribution system favourably affects customer delivery rates in two ways: First, delivery costs are shared over more GJs of natural gas, thus reducing the delivery charge per GJ; and second, adding NGV load is one of a few means available to FEI to combat declining throughput.

13.1 Please list all of the barriers to FEI building this load more quickly for the benefit of all customers on its system.

Response:

Most of the barriers to the adoption of natural gas as a vehicle fuel in the markets targeted by the GGRR pertain to the fact that natural gas technology is not well known and accepted as yet in the market and the fueling infrastructure is not broadly available. Fleet owners and operators see a significant risk in committing their business ventures to this new fuel and fueling technology. With these issues in mind the following are barriers (or perceived barriers) to the rapid adoption of natural gas.

1. Uncertainties about whether a significant positive fuel cost differential in favour of natural gas relative to diesel or gasoline will remain in the future, or whether new taxes will be imposed on NGT, is a barrier.
2. The cost differential between CNG/LNG trucks and diesel/gasoline trucks is a significant barrier impacting the payback period and therefore the numbers of trucks purchased. As economies of scale are improved, this cost differential should narrow.
3. Uncertainties about maintenance costs, and how operation and maintenance of the natural gas-fuelled vehicles will integrate with the remainder of the owner/operator's fleet still using conventional fuel and established maintenance practices, is a barrier. Uncertainties about vehicle life expectancy is a related concern.
4. The lack of established fueling station infrastructure is a concern and a barrier for fleet owners and operators. They are concerned, even if they have a dedicated station for their needs, as to what will be available as backup if their station must be shut down for unexpected repairs, or if natural gas or LNG supply is interrupted. The lack of

established CNG/LNG refueling station corridors for heavy duty trucks is a barrier to using CNG or LNG on longer haul routes..

5. The power and performance of LNG engines must prove out well in comparison to existing diesel equipment to provide a compelling argument to justify the adoption of natural gas for transportation by train (CNR and CPR) and marine vehicles in the BC Ferries fleet. Uncertainties about engine performance is a barrier to switching to LNG from conventional fuels.
6. Regulatory approval requirements may pose a barrier to building this load quickly. Timely and efficient review by the Commission of any rate and facilities applications filed in support of the GGRR initiatives is important to enable load building to occur more quickly. Please see CEC IR 1.13.2 for additional discussion on Commission approvals needed to facilitate this objective.

13.2 Please describe what would be necessary for the Commission to approve expenditures and or loans to accelerate the NGT market transformation.

Response:

The Commission is not tasked with approving the expenditures and/or loans per se. Rather, under the GGRR the Commission is charged with establishing rate mechanisms that ensure the recovery of costs related to prescribed undertakings. The Commission should approve FEI's requests as set out in the Application with regard to rate treatment of the GGRR prescribed undertakings. The issuance of the GGRR has provided a conclusive signal that the Government wants to see accelerated adoption of natural gas in the transportation market for the purpose of encouraging GHG reductions. Approval of FEI's requests in the Application will facilitate carrying out the prescribed undertakings on a timely basis to assist in the achievement of the objective. In addition, with a Commission decision in place, the "rules of the game" are clarified and the greater certainty will increase the confidence in market participants that it is worth their while to develop a proposal. FEI has a unique opportunity as it has demonstrated with the NGT customers being served to date that it can expand the NGT market in British Columbia.

Another key requirement in the transformation of the NGT market is FEI's Application currently before the Commission to expand and make permanent Rate Schedule 16 which provides LNG service to the transportation market. A timely and favourable Commission decision on the Rate 16 application is essential for transformation of the NGT market.

13.3 Please confirm that in addition to being a means of combating declining throughput the expansion of the NGT market transformation it will also be a means of mitigating future price increases related to the commodity price of natural gas.

Response:

The commodity price of natural gas is set in the marketplace and the current low prices are linked to large scale changes in the natural gas supply sector such as the large increases in supply availability arising from the development of shale gas deposits across North America. FEI does not expect this program to alter the market dynamics and pricing fundamentals in commodity markets.

However, additional NGV load does, other things equal, reduce the delivery rate as described in the above quote. As fixed costs are spread over a higher volume there will be a lower delivery rate. Therefore the overall rate impact to the customer is lower than it otherwise would be if a throughput increase did not occur.

14. Exhibit B-1, Page 44

> The NGV incentives of $5.6 million provided in 2010 and 2011 were prudent expenditures and in the public interest. They generated throughput, represented an investment in promoting a much larger potential market, and were supported by the same policy considerations that underpin the prescribed undertaking expenditures for vehicle incentives in the GGRR. Given

14.1 Please describe the FEI views on what the public interest assessment of the Commission should consider with respect to this $5.6 million investment.

Response:

This question is related to the recovery of past incentives, which is the subject matter of Phase 3 of this proceeding. FEI understands that Phase 3 will have its own process. As such, FEI respectfully submits that the question should be deferred until the Phase 3 process.