Reference: System of Accounts

Question:

1. Provide a copy of EGNB's system of accounts. These accounts should be disaggregated down to the sub-account level.

   Note: An example of the level of disaggregation is the list of detail accounts provided in Regulation 99-62. While EGNB is not presently required to maintain a system of accounts identical to those identified in Regulation 99-62, it is expected that the Utility, as part of good record keeping practice, would maintain a level of account detail similar to that listed in this Regulation.

2. In MS Excel electronic format, for each of the detail accounts referenced in Question 1 above, provide budget and actual figures for fiscal years 2007, 2008, and 2009.

3. In MS Excel electronic format, for each of the detail accounts referenced in Question 1 above, provide budget and forecast figures for fiscal year 2010, as well as year-to-date actual figures, as available.

4. In MS Excel electronic format, for each of the detail accounts referenced in Question 1 above, provide budget figures for fiscal year 2011.

Response:

1. EGNB's system of accounts is comprised of Cost Centres and Natural Accounts. Cost Centres are typically associated with a department or grouping of costs. The Cost Centres in EGNB's system of accounts are:

CC	Description
25300	ENB CORPORATE MANAGEMENT
25310	Available
25311	FINANCIAL REPORTING
25312	INFORMATION TECHNOLOGY
25313	CORPORATE ADMINISTRATION
25314	BUDGET AND FORECAST
25320	HUMAN RESOURCES
25330	SALES
25331	TRAINING AND SERVICE
25332	ADVERTISING AND PROMOTION
25333	HVAC INSTALLATION LABOUR
25334	UTILITY GAS
25335	AUTHORIZED DEALER NETWORK
25336	PROJECT MANAGEMENT
25337	INSIDE SALES AND SERVICE
25338	ATTACHMENTS
25340	CORPORATE - OTHER
25350	LOGISTICS
25351	CONSTRUCTION & MAINTENANCE
25352	PLANNING AND TECHNICAL SERVICES
25353	TRAINING & SERVICES
25354	ENGINEERING QUALITY & ASSURANCE
25360	Available
25361	REGULATORY
25362	CUSTOMER CARE
25363	GAS SUPPLY

Natural Accounts are used to identify specific types of expenditures within a Cost Centre. A copy of the Natural Accounts included within Enbridge Inc.'s system accounts, all of which are available for EGNB to use, are attached.

2. EGNB does not utilize all of the Cost Centres and Natural Accounts identified in the response to 1. above. Actual and budget figures for the Cost Centres and Natural Accounts used by EGNB in 2009 are attached in MS Excel electronic format. EGNB notes that the actual figures do not contain the proposed adjustments for corporate allocations as they had not been entered into our accounting system during the 2009 fiscal year.

   EGNB does not believe the requested information for 2007 and 2008 is relevant for this proceeding as these amounts have already been reviewed and approved by the Board.

3. The requested information is attached in MS Excel electronic format. EGNB notes that EGNB does not prepare its annual budgets or forecasts at the individual account level, for items other than Operating and Maintenance ("O&M") accounts, which are prepared for each cost centre by account by the cost center managers. Budgets and Forecasts for balance sheet and income statement items other than O&M are prepared using major account groupings within EGNB's modeling tool. As a result, the budget and forecast figures for 2010 are zero for all items excluding O&M.

4. Please see EGNB's response to Board Interrogatory No. 13.

Reference: Revenue Forecasting.

Question:

1. For each customer class, provide forecast and actual figures for customer additions, customer losses, total number of customers, throughput, and revenue for fiscal years 2007, 2008, and 2009.

2. For each customer class, provide forecast figures for customer additions, customer losses, total number of customers, throughput, and revenue for fiscal year 2010.

3. For each customer class, provide the calculations to support the total number of customers by customer class provided in Note 7 of Exhibit A, Schedule 7, Page 6.

   Note: The response to this question should include, by customer class, the number of customers at the beginning of forecast year 2011, number of additions during the year based on historical attachment rates, the number of additions based on assessment of current market potential, the number of additions attributable to capital investments proposed for 2011, and the number of drops during the year, the throughput, and the forecast revenue.

   The small general service (SGS) class should be disaggregated into SGSRE, SGSRO, and SGSC classes consistent with Exhibit A, Schedule 9, Page 3 of the evidence.

Response:

1. The following table provide the requested information for 2009:

	Customer Additions		Existing Customer Changes	Total Customer Count		Throughput (TJs)		Revenue ($000s)	
2009	Actual	Budget		Actual	Budget	Actual	Budget	Actual	Budget
SGSRE	307	1,148	(1)	2,009	2,536	180	216	1,512	1,432
SGSRO	268	204	(38)	4,989	5,114	359	367	3,491	4,740
SGSC	132	526	(36)	1,406	1,773	254	354	1,980	3,857
GS	126	260	30	1,521	1,648	1,066	1,218	7,581	12,988
CGS	23	24	(27)	246	278	1,011	1,173	6,501	11,475
LFO	1	-	1	24	22	1,367	2,203	4,680	7,548
HFO	2	-	-	9	7	974	906	418	573
Total	859	2,162	(71)	10,204	11,378	5,211	6,437	26,162	42,612

   The existing customer changes column reflects changes in the net number of customers during 2009, excluding new customer attachments. This includes showing customers that may have changed rate classes during the course of the year.

   EGNB does not believe that the requested information for 2007 and 2008 is relevant as these years have already been reviewed and approved by the Board.

2. Please see the following table for the requested information:

	Customers		Forecast Throughput (TJs)	Forecast Revenue ($,000)
	Forecast Additions	Forecast Total		
SGSRE	338	2,335	188	1,934
SGSRO	276	5,276	353	4,595
SGSC	94	1,730	284	3,266
GS	101	1,365	988	10,974
CGS	36	305	1,068	11,510
LFO	1	26	1,410	6,986
HFO	-	8	1,049	717
Total	846	11,045	5,340	39,982

EGNB does not forecast customer losses. As a result, EGNB is unable to provide this information.

3. The following table provides the requested information regarding customer additions:

	Dec 31/10 2010 Forecast Customers	**2011 Forecast Customer Additions**													**Dec 31/11 2011 Budget Customers**
		Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**	
SGSRE	2,335	6	14	9	8	5	23	29	36	55	51	48	49	**333**	2,668
SGSRO	5,217	22	8	4	4	12	18	23	32	49	40	34	36	**282**	5,499
SGSC	1,693	10	8	8	5	7	8	8	7	18	27	24	14	**144**	1,837
GS	1,331	8	8	4	2	5	8	4	8	11	18	8	11	**95**	1,426
CGS	296	2	2	-	-	4	3	-	2	8	2	2	2	**27**	323
LFO	27	-	-	-	-	-	-	-	-	-	-	-	-	**-**	27
HFO	8	-	-	-	-	-	-	-	-	-	-	-	-	**-**	8
OPS	15	-	-	-	-	-	-	-	-	-	-	-	-	**-**	15
CLVOPS	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**	-
	10,922	**48**	**40**	**25**	**19**	**33**	**60**	**64**	**85**	**141**	**138**	**116**	**112**	**881**	**11,803**

Please see the response to AWL Interrogatory No. 20 for information regarding historic attachment rates and the manner in which the 2011 attachment budget was developed.

EGNB does not forecast for customer losses. As a result, EGNB is unable to provide this information.

Please see the response to Board Interrogatory No. 16 for information regarding forecast throughput and revenues.

Reference: 2011 Budget (Exhibit A, Schedule 7) and the Spreadsheet Program.

Question:

1. Provide an electronic copy of the spreadsheet used to generate the balance sheet and income statement projections for fiscal year 2011. Provide this copy in Excel format. Do not lock any cells. To the extent these materials are deemed to be confidential, please provide the Public Intervenor with a suitable Confidentiality Undertaking in order to accommodate this request.

2. For each expense account that is generated in whole or in part through the use of a formula, provide both the account name and the formula.

3. Using the spreadsheet program, rerun the 2011 budget by adjusting the revenue projections to account for the average forecast error in revenue projections experienced in fiscal years 2007, 2008, and 2009.

   Please note that average forecast error should be calculated as total actual distribution revenue for the three years minus total forecast distribution revenue for the three years divided by total actual distribution revenue for the three years, all times 100. This is your average percentage forecast error. Provide your calculations of this average percentage error in your response.

4. Please provide a forecast cash flow statement for 2011.

Response:

1. The spreadsheet used to generate the balance sheet and income statement projections for fiscal year 2011 is attached in Excel format, with its formulae intact. EGNB relies on a large collection of spreadsheets that are integrated through the use of complex macros to develop its forecasts. While requests regarding the basis for arriving at specific aspects of the forecast are relevant, EGNB does not believe providing this entire collection of information is relevant to this proceeding.

2. Please see the response to 1. above. Since EGNB has provided the spreadsheet with its formulae intact, EGNB believes the Public Intervenor has the ability to determine the requested information and does not believe it is appropriate or necessary to duplicate it.

3. Completing this request calls for hypotheticals not supported by EGNB, and EGNB believes this is not reasonable or relevant. The Public Intervenor can prepare this based on EGNB's response to 1.

4. The following table provides the requested cash flow statement:

Enbridge Gas New Brunswick
Forecast Statement of Income
Years ending December 31, 2011
(in thousands of dollars)

	2011
Cash provided by (used in)	
Operating Activities	
Net earnings for the year	27,666
Items not affecting cash	
Regulatory deferral	(7,352)
Amortization of deferred charges & intangible assets	2,946
Amortization of property, plant and equipment	6,145
	29,405
Net change in non-cash working capital related to operations	
Decrease(increase) in accounts receivable	1,861
Decrease(increase) in inventory	-
Increase(decrease) in accounts payable and accrued liabilities	191
Increase(decrease) in long term post employment liabilities	-
	31,457
Financing Activities	
Change in partner's equity	6
Increase (decrease) in long term advances from affiliates	-
Increase(decrease) in bank indebtedness	(3,835)
	(3,829)
Investing Activities	
Decrease (increase) in restricted term deposit (short term investments)	-
Decrease (increase) in deferred carrying charges	(1)
Additions to development O&M capitalized costs	(11,741)
Decrease (increase) to CWIP	(18)
Additions to property, plant and equipment	(15,868)
	(27,628)
Change in cash	-
Cash - beginning of year	-
Cash - end of period	-

Reference: 2011 Budget (Exhibit A, Schedule 7) and the Regulatory Deferral.

Question:

1. Provide a detailed reconciliation of the difference between the $7.352 million addition to the regulatory deferral referenced in Exhibit A, Schedule 7, Page 2 of this proceeding and the $1.018 million addition to the regulatory deferral given in Exhibit C, Schedule 1, Page 2 of EGNB's evidentiary filing in NBEUB 2010-003 (the recently completed Cost of Capital proceeding).

Response:

1. The $6.334 million difference in the addition to the regulatory deferral amounts in the referenced exhibits is primarily due to:

    - a reduction in revenue ($6.274 million) primarily due to a reduction in customer attachments and a reduction in throughput of existing customers and forecast attachments.
    - an increase in return on equity ($0.121 million) due to an increase to ratebase and the addition of previously excluded corporate allocations.
    - partially offset by a reduction in expenses ($0.061K) primarily due to a reduction in O&M expenses (resulting from revised O&M capitalization rates), bad debt expense (due to reduced revenue), municipal and other taxes, and amortization (due to a reduction in additions to ratebase).

Reference: 2011 Budget (Exhibit A, Schedule 7) and Long-Term Advances.

Question:

In Exhibit A, Schedule 7, Page 5, Note 5, there is reference to the forecast issuance of a promissory note for $8,201,000 on December 9, 2010, and the forecast issuance of a promissory note for $1,000,000 on December 9, 2011. Please respond to the following:

1. What is the basis of the ten-year maturity period for both issues?

2. For what purpose(s) will the proceeds of the December 9, 2010 issue be applied? Identify the timing of outlays associated with this issue.

3. For what purpose(s) will the proceeds of the December 9, 2011 issue be applied? Identify the timing of outlays associated with this issue.

Response:

1. Historically EGNB has taken promissory notes with a ten-year maturity period as these rates have proven to be the preferable rates on a long-term basis. In December of 2008 and June 2009, promissory notes were taken with a five-year maturity period due to the increased rates being quoted on ten-year maturity periods, as a result of the credit crises at that time. Since that time, the credit crisis has relaxed and ten-year maturities are expected to once again provide preferred rates.

2. In preparation for year end 2010, EGNB forecasts its cash requirements necessary to balance cash to zero. EGNB also looks at the form of funding that will be used to satisfy the cash requirements (i.e. debt or equity). The December 9, 2010 promissory note represents the forecast cash requirements when the budget was prepared that were expected to be funded by debt. The proceeds represent the shortfall in cash received versus cash expensed for additions to ratebase and day-to-day operations.

3. Please see the response to 2. above. The same rationale is applicable to the forecast December 9, 2011 issue.

Reference: 2011 Budget: Exhibit A, Schedule 7.

Question:

1. Page 2, Gas Distribution Revenues:

   a. In MS Excel electronic format, please provide the detailed gas distribution revenue forecast, showing number of customers by rate class, rates, throughput, and class revenues. Please include the analysis showing how forecast rates by class were derived from competing fuel prices and other factors.

   b. Please identify the key factors leading to the reduction in 2011 gas distribution revenues from the $59.9 million forecast used in the 10-year forecast in the Cost of Capital proceeding and the revised $54.4 million forecast.

   c. Please provide all sensitivity and risk analyses performed by EGNB with respect to the assumptions for number of customers by rate class, rates derived from competing fuel prices, and throughput.

2. Page 2, Installation Services:

   a. Please provide an explanation for the significant reduction in both I/S revenues and costs in the current 2011 forecast from that presented in the 10-year forecast in the Cost of Capital proceeding.

3. Page 3, Distribution Plant costs:

   At year-end 2009, the cost basis for distribution mains plant was $97.4 million. In the 10-year forecast used in the cost of capital proceeding, this was forecast to increase to $105.0 million in 2010 and $110.7 million in 2011. The 2011 budget now shows $116.7 million.

   a. Please provide an explanation for the upward revision in mains capital expenditures.

   b. Street services show a similar pattern, albeit less extreme. Please provide a similar explanation.

4. Page 8, O&M Expense:

   a. Please provide the details of the capitalization percentages by account, showing the total account expense and capitalization percent.

   b. Please explain any differences between the capitalization assumptions used in the referenced document and those used in the 10-year forecast used in the Cost of Capital proceeding.

   c. Please explain generally why the amount capitalized to development O&M is higher in the current forecast than in the 10-year forecast, while O&M expenses are generally now lower.

5. Page 12, Affiliate Transactions:

a. Please provide a version of the referenced statements for 2011 if EGNB's proposal to include all allocated corporate services costs in the revenue requirement is not accepted by the Board.

b. Please provide a version of this exhibit for each year from 2001 to 2010. Please include versions based on allocated corporate costs and costs included in the revenue requirement.

6. Reference Exhibit A, Schedule 7:

a. Please provide the current forecast for 2010 in this format.

b. Please provide the detailed assumptions used to derive the 2010 revenue forecast, including number of customers by rate class, rates, throughput, etc.

Response:

1.

a. Please see the response to Board Interrogatory No. 16 for the gas distribution revenue forecast information. A spreadsheet in electronic format showing the derivation of the forecast rates is attached. EGNB notes that at the time the budget was prepared a simple average of the market data was used for forecasting retail oil prices in determining the 2011 rates.

b. The $5.5 million reduction in the 2011 gas distribution revenues from the 10-year forecast is primarily due to reduced LFO revenue expectations ($1.6 million) resulting from the June 3, 2010 Board decision, lower anticipated LFO consumption ($2.2 million) based on existing customer consumption and the removal of a new LFO customer that was expected, lower customer consumption in other rate classes ($1.3 million) based on recent consumption patterns, and reduced volumes associated with new customer attachments ($2.4 million) due to revised market expectations and a reduction in the standard new customer profiles. These have been partially offset by strengthened commodity market conditions ($1.9 million).

c. EGNB performed six sensitivity and risk analysis scenarios with respect to the assumptions for number of customers by rate class, rates derived from competing fuel prices and throughput.

i. Current approved rates – Distribution rates were updated to reflect the currently approved distribution rates (e.g. no rate increase).
ii. Downside commodity rate – Distribution rates were updated to reflect commodity pricing provided by the Enbridge Inc. Risk Assessment group based on historic volatility in the one year forward curve that provides a pessimistic impact on rates.
iii. Upside commodity rate – Distribution rates were updated to reflect commodity pricing provided by the Enbridge Inc. Risk Assessment group based on historic volatility in the one year forward curve that provides an optimistic impact on rates.

iv. Worst commodity rate - Distribution rates were updated to reflect commodity pricing provided by the Enbridge Inc. Risk Assessment group based on historic lows in the one year forward curve that provides a pessimistic impact on rates.

v. 25% reduced attachments – Customer attachments are reduced by 25% across all rate classes.

vi. 25% increased attachments – Customer attachments are increased by 25% across all rate classes

The following table summarizes the impact of each of these scenarios when compared against key metrics from the 2011 budget:

	Number of Customers	Total Throughput (TJs)	Distribution Revenue ($ millions)	IS Margin ($ millions)	Incentives ($ milllions)	Construction Estimate ($ millions)	Ratebase ($ millions)	Deferral Addition ($ millions)
2011 Budget	11,803	5,814	54.2	0.9	5.2	10.9	454.9	6.4
Sensitivity Scenario	**Change to 2011 Budget due to Sensitivity Scenario**							
Current approved rates	-	-	(3.4)	-	-	-	3.0	3.5
Downside commodity rates	-	-	(24.2)	-	-	-	23.4	25.5
Upside commodity rate	-	-	27.9	-	-	-	(27.4)	(29.4)
Worst commodity rate	-	-	(43.9)	-	-	-	43.8	47.0
25% reduced attachments	(220)	(55)	(0.8)	(0.2)	(1.3)	(1.2)	(1.6)	2.4
25% increased attachments	221	22	(3.1)	0.1	1.3	0.4	4.4	3.2

2.

a. The reduction in Installation Services revenues and costs in the 2011 budget is primarily due to a reduction in the expected workload due to reduced customer attachments and participating in a lower percentage of work in the commercial sector.

3.

a. The $6.0 million upward revision in distributions mains plant is primarily due to higher a higher opening balance in 2011 ($3.5 million) due to a modeling inconsistency and the addition of the expansion project to the Village of Dorchester ($2.7 million).

b. Street services have declined by $2.0 million in the 2011 budget, primarily due to a lower opening balance in 2011 ($1.4 million) due to lower attachments and reduced cost expectations for the Automated Meter Reading project in 2011 due to revised project cost projections.

4.

a. The following table provides the requested information (in $000s):

	Total O&M	Capitalized	Expensed	% Capitalized
Corporate Management	1,258	814	444	65%
Corporate Administration	1,757	1,142	615	65%
Financial Reporting	826	542	284	66%
Information technology	1,001	538	463	54%
Regulatory & upstream	1,573	945	628	60%
Sales & marketing	8,246	7,304	942	89%
Distribution & maintenance	6,133	3,168	2,965	52%
Customer care	1,374	23	1,351	2%
Human resources	2,472	1,437	1,035	58%
Gas transportation and related activities	1,170	-	1,170	0%
Total	25,810	15,913	9,897	

b. The following table compares the capitalization rates used in the 10-year forecast in the Cost of Capital proceeding and the 2011 Budget:

Department	2011 COC Rates	2011 Budget Rates
Attachments	67.0%	65.5%
Construction & Maintenance	67.0%	28.3%
Corporate Admin	18.3%	65.0%
Corporate Management	49.7%	64.7%
Customer Care	6.4%	1.7%
Eng QA	67.0%	15.0%
Financial Reporting	49.7%	65.7%
Forecast & Budget	N/A	N/A
Gas Supply and Control	0.0%	0.0%
Human Resources	49.7%	58.1%
Incentives	80.0%	100.0%
Information Technology	49.7%	53.8%
Installations - Project Mgmt	76.5%	74.5%
Installations - HVAC	76.5%	74.5%
Logistics	67.0%	76.7%
Marketing	76.5%	69.4%
Planning	67.0%	47.2%
Regulatory and Budgets	66.0%	64.6%
Sales	76.5%	69.4%
Service	67.0%	66.1%

Changes in capitalization rates are based on a study conducted by EGNB in 2010 that is discussed in the response to Flakeboard Interrogatory No. 10.

c. The amount capitalized to Development O&M in the 2011 Budget is higher than in the 10-year forecast due to two factors. First, the O&M Capitalization percentages in the 2011 Budget are slightly higher than the 10-year forecast, resulting from the capitalization study that was performed, adjusting some of the assumptions that had been made for 2011 in the 10-year forecast. Secondly, there is a different mix of O&M expenses (ie. change in amounts to each cost centre) which can change the amount capitalized to Development O&M.

5.

a. EGNB is not able to speculate as to what the Board may or may not determine to be acceptable allocated corporate costs to be included in the revenue requirement. As a result, EGNB is unable to provide the requested statements.

b. The final and approved versions of the notes to the financial results outlining the Affiliate transactions for the years 2001 to 2010 are attached. For the years 2009 and 2010, EGNB has shown the tables with current allocation methodology and proposed allocation methodology, as requested. For the years 2001-2008 EGNB did not restate the notes to include full corporate allocations in 2001 to 2008. The allocated costs for these years have already been reviewed and approved by the Board. As a result, EGNB does not believe restated tables are necessary or relevant to this proceeding.

6.

a. The 2010 Forecast in the same format as Exhibit A, Schedule 7 is attached.

b. Please see the attached revenue reconciliation that provides the requested assumptions. To ensure this table reconciles with the gas distribution revenues included in the forecast, a miscellaneous revenue line item has been included. This was necessary due to the minor variances in the assumptions applied to different components of the budget model that cannot be reconciled in this combined spreadsheet.

Reference: 2011 Budget: Exhibit A, Schedule 8.

Question:

1. Page 6, O&M Capitalization:

    a. Please provide the capitalization assumptions used in each account in each year in Table 3.

    b. Please provide the reasons for any variations in capitalization assumptions from year to year.

Response:

1. Please see the response to AWL Interrogatory No. 21.

2. Please see the response to Flakeboard Interrogatory No. 10.

Reference: 2011 Budget: Exhibit A, Schedule 9

Question:

1. Page 5, O&M Capitalization Rates:

   a. Provide copies of all documentation, including any studies conducted by EGNB, 3rd party consultants, or any of its affiliates, that would support the capitalization rates on provided on Page 5 of Schedule 9.

Response:

1.
   a. Please see the response to Flakeboard Interrogatory No. 10

Reference: Corporate Allocations Proposal

Question:

1. Reference Exhibit A, Page 3, Answer 6:
   a. Please provide a copy of the referenced report prepared by Mr. Easson.

   b. Provide copies of all emails or other written communication between EGNB, Mr. Easson, and the Public Utilities Board (PUB) on this matter.

2. Reference Exhibit A, Schedule 3:
   a. Has this document been approved, modified or rejected by a utility regulator? If so, please identify the specific regulatory decisions in which this document has been evaluated, and provide either a copy of, or internet reference to, each such decision.

   b. Please identify all regulatory decisions within the past five years affecting Enbridge affiliates in which allocated costs based on this document have been approved, rejected or modified. Please provide either a copy of, or internet reference to, each such decision.

3. Reference Exhibit A, Schedule 4:

   a. In MS Excel electronic format, please provide copies of this schedule for 2002 to 2009. Please indicate the magnitude of the costs that were allowed in the revenue requirement in each year.

4. Reference Exhibit A, Schedule 4:

   a. Please provide a version of this exhibit which shows the total Enbridge cost allocated in 2009 and the allocation methodology used to assign the cost to EGNB. For those costs which are not directly assigned, please also provide the value of the allocation factor used for EGNB (e.g., number of customers) and the value for all of Enbridge.

   b. For each cost item shown in this exhibit, please provide a reference to the corporate department and department number as used in Appendix C to Exhibit A, Schedule 3. Where no specific department applies, please describe the specific costs that are being allocated, and identify the value to EGNB.

5. Reference Exhibit A, Schedule 4. To the extent not otherwise explained in the previous IR:

   a. Please detail the specific insurance premium costs being allocated to EGNB, and explain the value of each policy to EGNB.

   b. Please explain what "stock based compensation" is. To the extent that it represents executive compensation, please identify the individuals who are eligible for this compensation and the amounts provided to each. Please explain the value of those costs to EGNB.

c. Please identify the rent and leases costs that are allocated to EGNB, and explain the value of those costs to EGNB.

d. Please explain what "enterprise architecture" is, and define its value to EGNB.

e. Please identify any specific value obtained by EGNB related to the "public affairs and corporate communication" costs.

Response:

1.
   a. Please see the attached report of Mr. Easson.

   b. Please see the attached exchange between Mr. Easson and Jamie Leblanc. EGNB is not aware of any other written communications regarding this matter.

2.
   a. Please see the response to AWL Interrogatory No. 8(i).

   b. Please see the response to AWL Interrogatory No. 8(i).

3.
   a. Please see the response to Board Interrogatory No. 10.

4.
   a. The following table shows the total Enbridge costs allocated in 2009, and the allocation methodology used to assign the costs.

Name	Allocation Methodology	2009 Allocated Costs
Audit Services - Shared fees	Capital Employed (Audit fees)	$ 29,790
Audit Services (Calgary)	Capital Employed	23,328
Benefits and Pensions	Enterprise FTE	5,325
Business Taxes	Corporate FTE	2,641
Chief Executive Officer	Capital Employed	27,536
Chief Financial Officer	Capital Employed	13,285
Chief Information Officer	Enterprise FTE	59,496
Corp Law General Expense	Time Estimate (Law)	9,540
Corp Secretarial Legal Fees	Capital Employed	17,490
Corporate Admin.	Calgary Office FTE	29,056
Corporate Aviation	Capital Employed	56,983
Corporate Controller	Capital Employed	70,387
Corporate HR	Enterprise FTE	44,905
Corporate IT Operations	Corporate FTE	87,739
Corporate IT Projects	Corporate FTE	8,470
Corporate Law	Time Estimate (Law)	9,507
Depreciation	Capital Employed	160,279
Directors Fees and Expenses	Capital Employed	64,040
Enterprise Financial System Support	User Counts	157,860
Enbridge Gas Distribution	Corporate FTE	4,997
Employee Benefits	Corporate FTE	177,529
Employee Development	Enterprise FTE	28,069
Enterprise Architecture	Enterprise FTE	26,833
Enbridge Pipelines Inc. Direct Charge	Corporate FTE	100,745
Financial Risk Management	Time Estimate (Risk)	28,443
Group VP Corp. Resources	Capital Employed	13,058
HRIS Services	Enterprise FTE	18,035
Industry Association Fees	Enterprise FTE	33,684
Insurance Premiums	Capital Employed	7,392
Labour Relations	N/A	210,638
Oracle Software Depreciation	Enterprise FTE	6,417
Other Employee Benefits	N/A	30,756
Planning and Development	Corporate FTE	137,337
Public Affairs and Corp. Comm.	Time Estimate (Plan)	10,799
Records Management (Knowledge Management)	Capital Employed	111,973
Rent and Leases	Capital Employed	14,397
Risk Management	Calgary Office FTE	57,744
Stock Based Compensation	Time Estimate (Ops)	1,874
Tax Services (Calgary)	Corporate FTE	390,397
Tax Services (Toronto)	Time Estimate (Tax)	32,407
Total Compensation	N/A	19,772
Treasury	Time Estimate (Treasury)	28,265
Total		**$ 2,369,217**

Please see the response to Board Interrogatory No. 9(A) for the basis for the allocation factors.

b. The following table provides the requested department references and the requested information for costs where no specific department applies:

Name	Corporate Allocation Methodology Reference	Description
Audit Services - Shared fees	Appendix B	Allows Enbridge Inc. ("EI") to operate and provide services to EGNB
Audit Services (Calgary)	Appendix C - 16.3.1.8	
Benefits and Pensions	Appendix B	Allows EI to operate and provide services to EGNB
Business Taxes	Appendix B	Overall Cost of EI operations from which EGNB would benefit
Chief Executive Officer	Appendic C - 16.3.1.2	
Chief Financial Officer	Appendix C - 16.3.1.5	
Chief Information Officer	Appendix C - 16.3.1.25	
Corp Law General Expense	Appendix C - 16.3.1.9	
Corp Secretarial Legal Fees	Appendix B&C - 16.3.1.10	
Corporate Admin.	Appendix C - 16.3.1.11	
Corporate Aviation	Appendix A&C - 16.3.1.34	
Corporate Controller	Appendix C - 16.3.1.6	
Corporate HR	Appendix A&C - 16.3.1.14	
Corporate IT Operations	Appendix C - 16.3.1.26	
Corporate IT Projects	Appendix C - 16.3.1.26	
Corporate Law	Appendix C - 16.3.1.9	
Depreciation	Appendix B	Depreciation on EI assets from which EGNB would gain value from
Directors Fees and Expenses	Appendix B	Fees for EI directors, who provide services to EGNB
Enterprise Financial System Support	Appendix C - 16.3.1.30	
Enbridge Gas Distribution	Appendix B	EGD services reallocated based on EGD employee time spent to service EGNB
Employee Benefits	Appendix B	Allows EI to operate and provide services to EGNB
Employee Development	Appendix C - 16.3.1.17	
Enterprise Architecture	Appendix C - 16.3.1.27	
Enbridge Pipelines Inc. Direct Charge	Appendix B	EPI services to EI. Allows EI to operate and provide service to EGNB
Financial Risk Management	Appendix C - 16.3.1.29	
Group VP Corp. Resources	Appendix C - 16.3.1.18	
HRIS Services	Appendix C - 16.3.1.14	
Industry Association Fees	Appendix B	Allows EI to operate and provide services to EGNB
Insurance Premiums	Appendix B	Refer to Public Intervenor Interrogary No. 9(5(a))
Labour Relations	Appendix C - 16.3.1.15	
Oracle Software Depreciation	N/A - Direct Billed by ECS	Relates to depreciaton on Oracle software used by EGNB in day to day operations
Other Employee Benefits	Appendix B	Allows EI to operate and provide services to EGNB
Planning and Development	Appendix C - 16.3.1.21	
Public Affairs and Corp. Comm.	Appendix C - 16.3.1.12	
Records Management (Knowledge Management)	Appendix A	Overall Cost of EI operations from which EGNB would benefit
Rent and Leases	Appendix B	Refer to Public Interrogary No. 9(5(a))
Risk Management	Appendix C - 16.3.1.13	
Stock Based Compensation	Appendix B	Overall Cost of EI operations from which EGNB would benefit
Tax Services (Calgary)	Appendix A&C - 16.3.1.7	
Tax Services (Toronto)	N/A - Direct Billed by EGD	Tax Services provided to EGNB staff as there are no tax resources on staff at EGNB
Total Compensation	Appendix C - 16.3.1.16	
Treasury	Appendix C - 16.3.1.28	

5.

a. The table below outlines the insurance premiums paid by EGNB in 2009 for insurance:

Property Insurance	1,800
Liability Insurance	174,175
Automobile Insurance	16,640
Executive Risk Insurance	7,237
Fiduciary Risk	2,774
Crime Insurance	2,384
Broker Insurance	5,629

These insurance policies provide value to EGNB in the following manner:

- Property Insurance protects against most risks to EGNB's property
- Liability Insurance protects EGNB against liability claims
- Automobile Insurance protects EGNB's vehicles against physical damage and liabilities resulting from traffic accidents

- Executive Risk Insurance mitigates the personal responsibility of EGNB's representatives
- Fiduciary Risk Insurance protects EGNB against claims against pension and savings plans
- Crime Insurance covers EGNB's losses due to criminal victimization
- Broker Insurance covers the Broker's commission for arranging EGNB's insurance coverage

b. Stock based compensation refers to compensation that is made in the form of stock options. Individuals at the Director level and above within Enbridge Inc. would typically be eligible for this compensation. The amounts provided to individuals within Enbridge Inc. are considered to be confidential and EGNB does not believe this information is relevant to this proceeding. As stock based compensation forms part of a competitive total compensation package for Enbridge Inc. employees, it supports the overall operations of Enbridge Inc. and Enbridge Inc.'s ability to attract and retain properly skilled employees. As articulated in Exhibit A, EGNB benefits from being part of an organization that has this caliber of staff.

c. The rent and leases costs that are allocated to EGNB are a portion of the rental and lease costs for Enbridge Inc.'s corporate offices. Which provides a location for the corporate employees? Without a corporate head office, EGNB would not be able to derive many of the benefits it receives from being part of Enbridge.

d. The enterprise architecture department Enbridge Inc. develops and monitors enterprise wide strategies, policies and standards for information technology. EGNB benefits from these services through use of Enbridge access to current information technology approaches, application suites, data storage in Toronto, software updates, training, etc. which are rolled out and governed by this corporate department.

e. Public affairs and corporate communications provides EGNB with access to a broader group of professionals that can provide advice on issues facing EGNB and approaches to address them. In addition, these costs support Enbridge Inc.'s activities to develop plans, messages and relationships that maintain and strengthen the reputation of Enbridge among external stakeholders. The overall strength of Enbridge and how it is perceived in the market provides a foundation for the benefits that EGNB receives from being part of Enbridge, including relying on the strength of the Enbridge name in dealings with industry stakeholders and the public.

Reference: EGNB′s 2009 Results.

Question:

1. Please describe the prudence standard which EGNB believes should apply to its 2009 financial results.

2. 2009 was the first year in EGNB's history where its year-on-year revenues declined. Please provide all analysis performed by the Company relating to the drop in revenue.

3. Please provide a graph for each rate class showing the rate in effect in each month of 2008 on one line and the rate in effect for each month for 2009 as another line.

4. EGNB's revenues were down from the year prior, while EGNB's addition to the deferral account and capitalized O&M rate base increased significantly. Please explain:
   a. When did EGNB know its revenues would be down relative to 2008?
   b. Did EGNB consider applying to the Board to suspend rate riders in order to reduce the revenue loss? Please explain why or why not. Please describe all other measures taken by EGNB to mitigate revenue loss.

5. Please describe whether EGNB has considered financial hedges to protect against an unfavorable development in the spread between gas and oil. Please provide all copies of analyses performed or reviewed by EGNB in this regard.

6. Please provide an analysis of the economic costs and benefits of EGNB's decision to issue over $45M in debt during 2009, while paying out nearly $25 million to equity investors.

7. Please explain why customer care costs have increased by 36% over the past year.

8. Please explain the increase in upstream costs over the past year.

9. Please provide any documents used to support EGNB's decision to use affiliates rather than third-parties for the 43% of Total Consulting and Services Expenditure.

10. Please provide all price comparisons, RFPs, or other documents compiled to ensure that EGNB is paying market rate and no more for each of the Consulting and Services expenses.

11. Please provide the components of the $24.5M distribution to partners. Please list each payment contained in this line item.

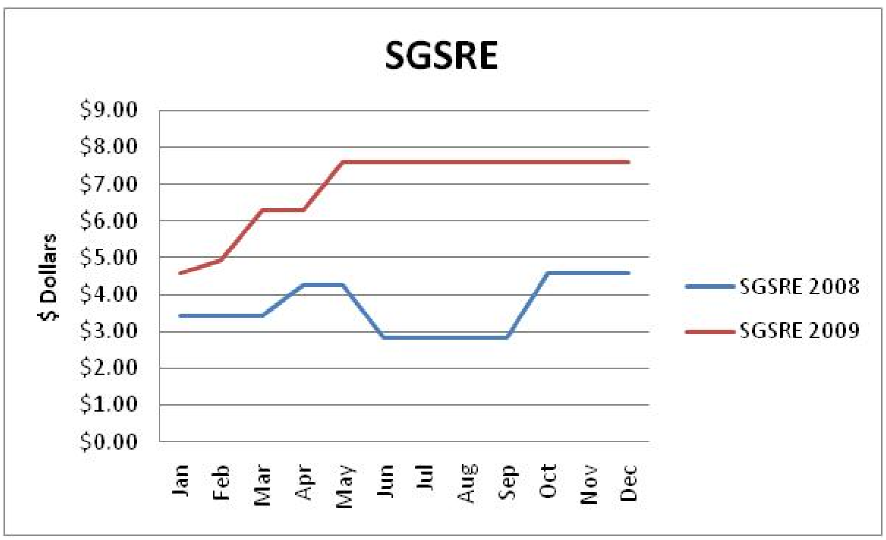
12. With reference to Exhibit A, Schedule 5, Page 13, what does the Total Consulting and Services column refer to? Identify all 3rd party contracts for each of the Consulting Services categories.

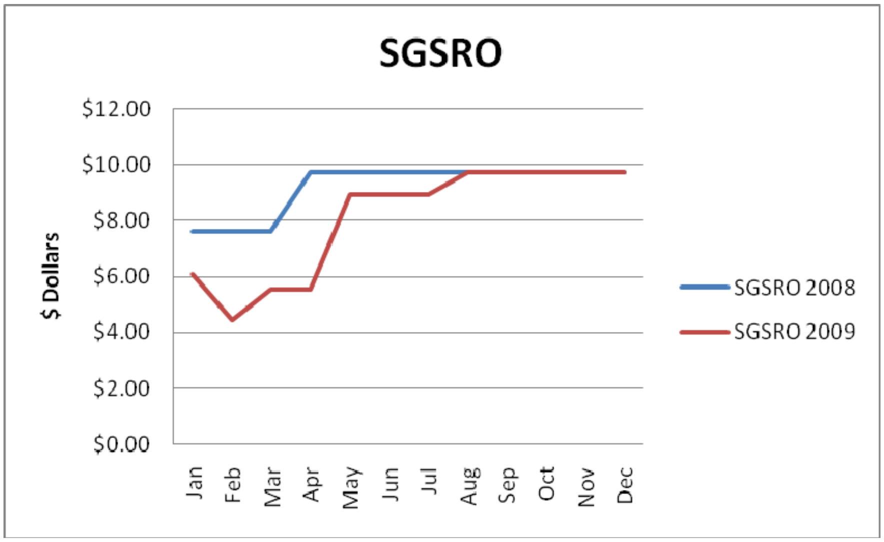
Response:

1. EGNB believes that the typical standard for prudence should apply to its 2009 financial results. Any decision of EGNB should first be presumed to have been made prudently unless a party demonstrates reasonable grounds to question the prudence of that decision. If this presumption of prudence is overcome, then EGNB must show that its business decision was reasonable under the circumstances that were known to, or ought to have been known to, EGNB at the time it made the decision.

2. The decline in EGNB's revenues in 2009 in comparison to 2008 is a direct result of the substantial rate riders that EGNB implemented during the 2009 heating season. No analysis was required to determine this fact.

3. The following graphs show the distribution rates in effect in each month of 2008 and 2009 for each rate class:




SGSRO
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$8.00
$6.00
$4.00
$2.00
$0.00
$ Dollars
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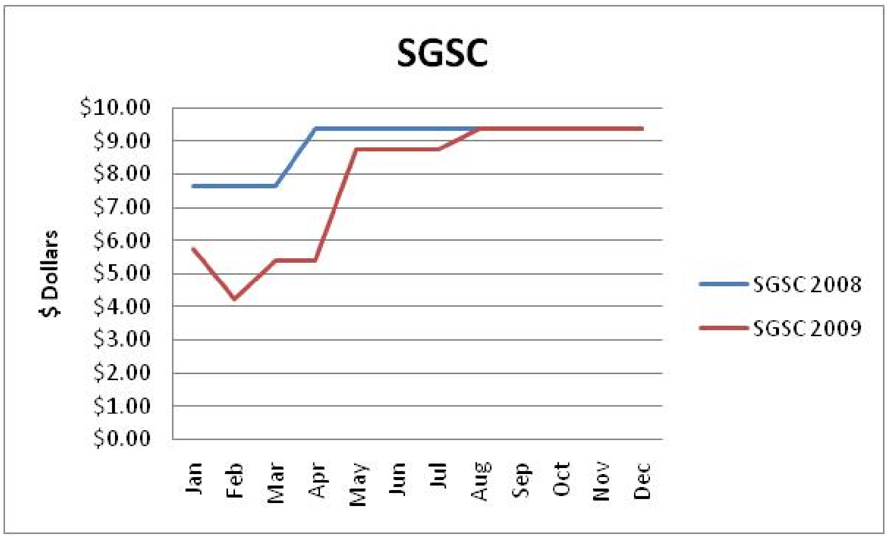
SGSRO 2008
SGSRO 2009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$4.00
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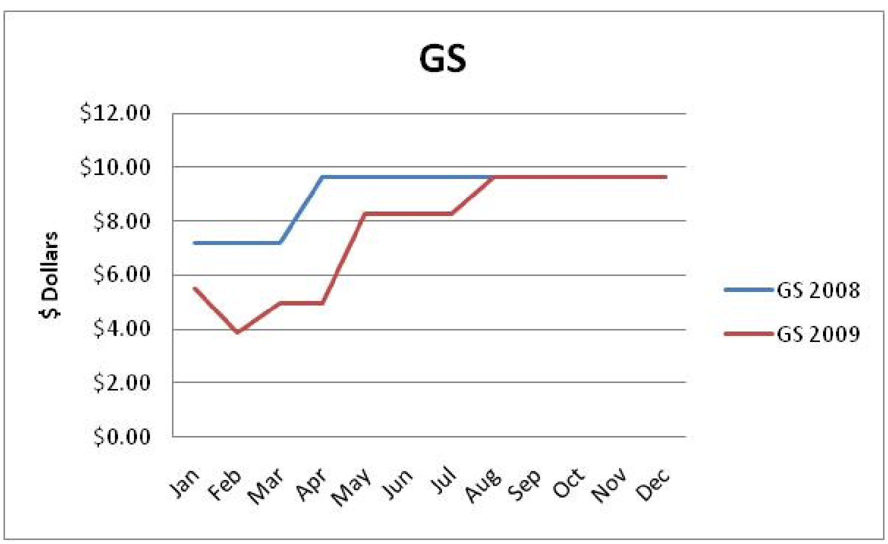
SGSC 2008
SGSC 2009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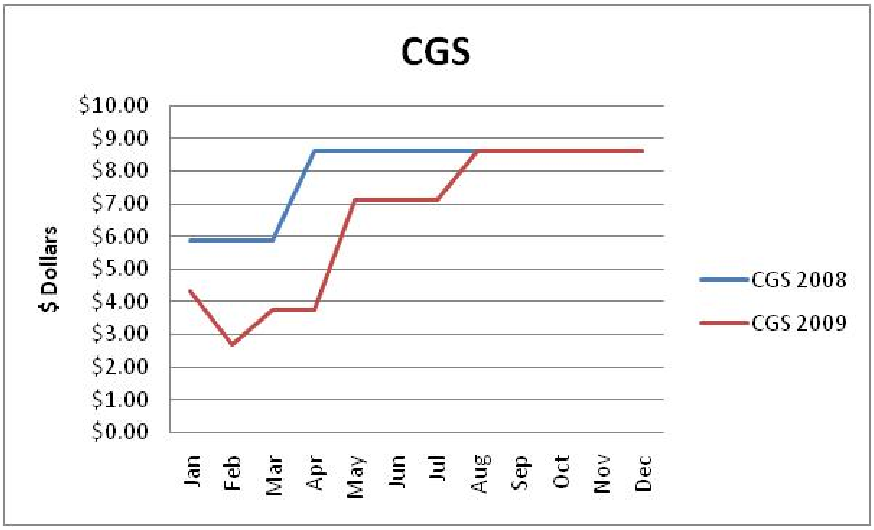
GS 2008
GS 2009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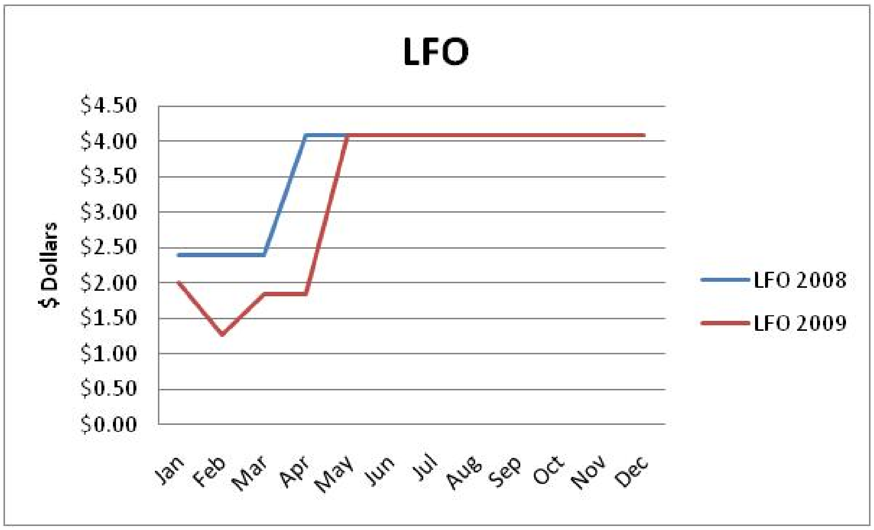
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
CGS 2008
CGS 2009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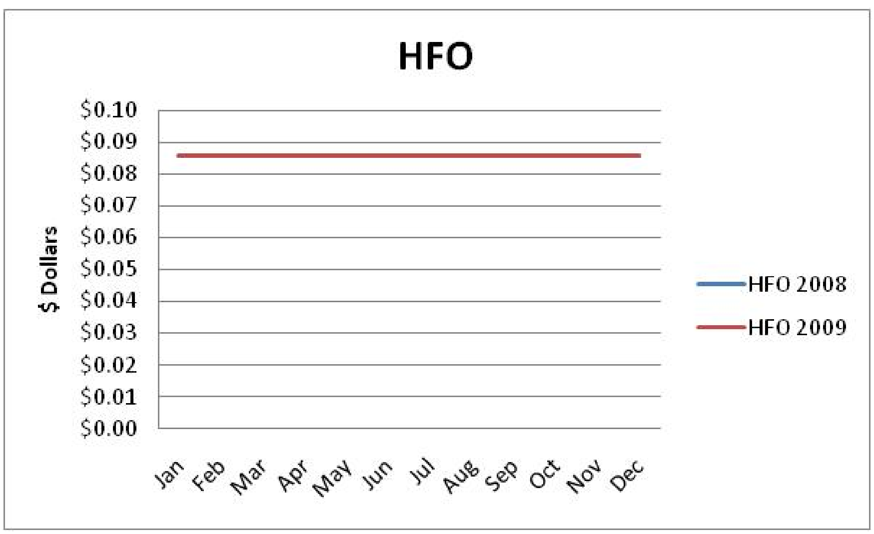
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
LFO 2008
LFO 2009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$0.07
$0.06
$0.05
$0.04
$0.03
$0.02
$0.01
$0.00
$ Dollars
Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec
HFO 2008
HFO 2009

4.
   a. EGNB recognized that its revenues would be down relative to 2008 after implementing rate riders in January and February of 2009. EGNB recognized that it was unlikely that the reduced revenues during the heating season could be recouped during the remainder of the year.

   b. EGNB did not consider applying to the Board to suspend rate riders in order to reduce the revenue loss. EGNB provides a value proposition to its customers that a target level of savings can be achieved by a typical customer converting to gas. Failure to adjust rates in support of this value proposition would compromise EGNB's integrity with its customers and its position in the marketplace.

5. In 2007, EGNB did consider financial hedges to protect against an unfavourable spread between gas and oil. Based on the analysis performed, EGNB determined that the expected costs associated with putting the hedges in place outweighed the benefits. A copy of this analysis is attached.

6. EGNB has not performed an analysis of the economic costs and benefits of issuing debt versus retaining earnings. The $45 million in debt was required to rebalance EGNB's capital structure, provide the necessary cash for operations and fund ratebase in 2009. If EGNB had retained the $25 million in earnings, an additional $20 million in debt funding would still have been required to provide cash for operations and to fund ratebase. Also, EGNB would have moved further above the 50% equity threshold than it was at the beginning of 2009. This would have led EGNB to take on $25 million in debt to buy out the additional equity to rebalance the capital structure to 50/50.

7. Customer Care costs increased over the past year primarily due to increased call centre and billing costs arising from two factors. First, EGNB's contract with its provider of call centre and billing services was coming to an end at the end of 2008. Faced with a 40% increase in costs being proposed by the provider, EGNB reviewed all of its options, and decided the most economic approach was to contract its call centre services with Gazifere and bring billing services in-house. While this represented an increase in costs, it provided an overall reduction in the costs for these services going forward as compared to the costs proposed by the previous provider. Second, as part of the transition to Gazifere, there was overlap in service providers during January and February 2009.

8. EGNB is assuming that this question refers to "Regulatory & Upstream" Operating and Maintenance costs shown in Note 6 on page 8 of the 2009 Financial Statements (Exhibit A, Schedule 5). The $520 thousand increase is primarily due to increased regulatory fees ($428K), which include costs associated with the Public Intervenor, increased legal fees ($77K) due to increased regulatory activity and increased regulatory professional consulting costs ($73K) in support of regulatory activities in 2009, partially offset by reduced salary and travel costs ($50K).

9. EGNB does not have any documents used to support the decision to use affiliates rather than third parties. As EGNB has indicated in the past, Enbridge affiliates are well positioned to

provide the services given their experience in gas distribution. The ability to draw on these competencies was one of the strengths seen by the Province in awarding the General Franchise to EGNB. Also, EGNB relied on previous reviews by the Board's consultants and decisions in the financial reviews that approved these costs.

In 2008, EGNB conducted a study that indicated its Customer Care costs would be reduced by performing the functions in house instead of using a third party. Subsequent to the study, Gazifere proposed to provide these services at a cost that was less than what EGNB estimated it cost to perform these functions internally. This provides EGNB with confidence that the use of an affiliate for these services is in the best interest of customers.

10. As indicated in the response to 9. above, EGNB does not have any price comparisons, RFPs, or other documents for the affiliate consulting services for the reasons articulated in that response.

11. The $24.5 million represents quarterly distributions to partners. A payment of $6.1 million was paid to partners in February 2009 in relation to 2008 Q4 earnings, $6.2 million was paid in May 2009 in relation to 2009 Q1 earnings, $6.2 million was paid in August 2009 in relation to 2009 Q2 earnings and $6.0 million was paid in October 2009 in relation to 2009 Q3 earnings.

12. The Total Consulting and Services column refers to the total amounts paid to affiliated and non-affiliated consultants and service providers. Consulting services include marketing program development and delivery, market research, financial audit, cost allocation and rate design, business valuation, IT System support, recruitment support and regulatory support. In 2009, third party consulting services were provided by:
    - Black and Veatch
    - Bristol
    - Colour Creative Persuasion
    - Cossette Communication
    - Knightsbridge Human Capital
    - KPMG LLP
    - M5 Marketing Communications
    - MJ Ervin and Associates
    - PriceWaterhouseCoopers LLP
    - Revolution Strategy
    - Robertson Surrette
    - SGCI Communications
    - Tectura Canada

Reference: EGNB′s Additions to Asset Base in 2009.

Question:

1. Please list each major (over $1M) addition to the Regulated Asset Base during 2009.

2. Please provide the internal business cases, cost/benefit analyses, or other documents used Please explain whether and how EGNB proposes to close the gap between revenues and expenses (including regulated return on equity and capitalized O&M).

3. Please provide a copy of the spreadsheet analytic tools EGNB used when determining whether to build service lines and meters in 2009.

4. Please provide a copy of the spreadsheet analytic tools EGNB used when determining whether to build a new distribution main in 2009.

5. Please provide a copy of the spreadsheet analytic tools used by when evaluating each customer incentive program used by EGNB in 2009. Please provide a cost-benefit analysis demonstrating that existing customers are no worse off as a result of each incentive program.

6. In 2009, was it EGNB's policy only to add new infrastructure when customer commitments guarantee the recovery of the costs of said infrastructure? If so, please indicate what form such customer commitments take (*e.g.*, signed contract, memorandum of understanding) and provide a copy of each customer commitment received by EGNB to support its expansion activities during 2009. Please also specify what financial security is sought from customers to assure that they perform on their commitments.

7. Regarding mains plant additions, please provide
   a. System map(s) showing each main addition project;
   b. Plant cost incurred for each project (by year, including 2009);
   c. New customers served by each project, and estimated throughput for each;
   d. Economic analysis justifying each expansion.

8. Regarding meters and services plant additions in 2009, please provide
   a. Number of meter and service additions by rate class;
   b. Cost of meter additions by rate class;
   c. Cost of service additions by rate class.

9. Reference EGNB 2009 Construction Plan, dated December 18, 2008:

   a. Please provide the actual results for 2009 compared to the forecasts shown in Tables 1 through 6 of the referenced document. Please provide an explanation for any material variances.

   b. Please provide system maps showing the location of the expansions reported in Tables 4 through 6.

   c. In Table 3 of the Annual Construction Report for 2009, EGNB forecasts a total addition to Distribution Plant of $10.28 million. In contrast, the regulatory financial statements show an increase of $16.61 million in gross Property Plant and Equipment from $155.58 million in 2008 to $172.19 million in 2009. Please explain in detail the difference between the forecast additions anticipated in Annual Construction Report for 2009 and the actual additions during 2009.. Please specify how much of the dollar difference is attributable to

      (1) The addition of more or less mains than anticipated in the Annual Construction Report for 2009.

      (2) The addition of more or less “Services” than anticipated in the Annual Construction Report for 2009.

      (3) A difference between the assumed cost of installing mains for planning purposes and the actual cost of installing mains for 2009. Please specify the unit cost for mains assumed for the Annual Construction Report and the actual unit cost incurred in 2009.

      (4) A difference between the assumed cost of “Services” for planning purposes and the actual cost of “Services” in 2009. Please specify the unit cost assumed for the Annual Construction Report for 2009 and the actual unit cost incurred in 2009.

      (5) Any other factors that contribute to the difference between forecast and actual distribution plant additions.

      Please provide supporting documentation for each difference identified above related to the cost of plant additions during 2009.

   d. EGNB states on page 3 that “actual pipeline construction in 2009 will be based on customer commitment along potential routes prior to constructing additional mains.” With respect to this statement:

      (1) Please provide documentation to support EGNB’s apparent position that the 2009 additions were all backed by customer commitments – e.g., signed contracts, or any other form of evidence that EGNB has to support this position.

      (2) Please specify the term of customer commitment sought by EGNB. Is it a one-year commitment, a ten-year commitment?

      (3) Please compare and contrast EGNB’s practices with regard to expanding infrastructure in response to customer commitments with those of Heritage Gas.

(4) Please provide a copy of the EGNB policies and procedures that document the policy of expanding infrastructure in response to customer commitments.

(5) Please provide all internal communications between EGNB management and the EGNB sales force related to the policy of requiring customer commitments. What guidance does EGNB management give its sales staff as to what constitutes an acceptable customer commitment?

10. Reference EGNB 2010 Construction Plan, dated December 18, 2009:

    a. Please provide an updated forecast for 2010 compared to the forecasts shown in Tables 1 through 6 of the referenced document. Please provide an explanation for any material variances.

    b. For each project identified in Tables 4 through 6, please provide the cost of the project, the additional customers served (by rate class), and the incremental annual throughput.

    c. For each project identified in Tables 4 through 6, please provide the economic analysis of the net revenues, incentives and costs associated with the project, justifying the expansion.

    d. Please provide the estimated 2010 throughput additions for each municipality shown in Table 1 of the 2010 Annual Construction Report.

    e. Please provide the estimated construction cost (broken out by mains and services, and on a per unit and total basis) for each of the projects identified in Tables 4-6 of the 2010 Annual Construction Report. Please provide the volume of customer commitments already obtained for each of the projects identified in Tables 4-6 of the 2010 Annual Construction Report. Please provide documentary evidence to support these customer commitments.

11. For comparison purposes and to facilitate the evaluation of the reasonableness of the 2011 budget, please provide the forecast unit cost of mains and services embedded in EGNB's proposed budget for 2011. Please provide supporting documentation for the reasonableness of these assumed unit costs.

Response:

1. The only major project in 2009 over $1 million was the Hanwell Road expansion project.

2. As described in EGNB's response to part 5. below, EGNB assesses the total value of the new revenues attached in a given year against the carrying cost of the capital employed to attach those customers. Since EGNB is focused on the economic expansion of the distribution system, the gap between revenues and expenses is narrowed when the value of the new revenues exceeds the carrying cost of attaching them.

3. The spreadsheet analytic tool that is used to determine whether to build mains and service lines and install meters is called the Project Return and Capital Request ("PRCR"). The PRCR is used to calculate the expected revenues, by rate class, and all capital costs associated with attaching a customer(s). A different PRCR is used for each of the nine communities to allow for potential differences in construction costs to be reflected. The evaluation resulting from using the PRCR is the Customer Profitability Index ("CPI") and simple internal payback which is noted on the spreadsheet as Payback (in years). The CPI calculation is similar to a net present value ("NPV") calculation where a CPI equal to one is the same as a NPV equal to zero. A sample PRCR is attached.

4. Please see the response to 3. above.

5. The spreadsheet analytic tool used to evaluate incentive programs and their impact on existing customers considers revenues generated by a customer addition and all capital costs, not just incentives. This analysis is performed on a portfolio basis, not on an individual incentive program basis. The following table provides an analysis of 2009 results:

Item	Capital[a]		
1	Main	$	5,524,260
2	Service Line/ Meter	$	3,163,209
3	Sales Incentive	$	4,200,831
4	**Total Capital**	$	12,888,300
5	**Cost of Capital**[b]		9.75%
	Depreciation Rates[c]		
6	Main & Sales Incentives		2.43%
7	Service Line/ Meter		3.83%
	Net Annual Impact on Revenue Requirement		
	Energy (GJs)[d]		330,061
	Revenue[e]	$	1,813,126
	Less:		
	Depreciation: Mains (item 1 * item 6)	$	134,240
	Depreciation: Service Line/ Meter (item 2 * item 7)	$	121,151
	Depreciation: Sales Incentive (item3 * item 6)	$	102,080
	Cost of Capital (item 4 * item 5)	$	1,256,609
	Annual Impact[f]	$	199,046

Notes:

a. Total expenditures on mains, services and incentives in 2009
b. Estimated weighted average cost of capital for 2009
c. Board approved depreciation rates
d. Total throughput attached during 2009
e. Estimated revenue attached in 2009 using effective rates for each class
f. Positive number indicates positive impact on revenue requirement from attaching customer

As the analysis indicates, on a portfolio basis, the 2009 additions to EGNB's distribution system, including the cost of incentive programs, reduced EGNB's revenue requirement by $0.2 million.

6. EGNB's practice is to ensure that in aggregate, the forecast revenues from new customers attached during a given year will exceed the carrying costs on the capital employed to attach customers during that year (e.g. mains, services, meters, incentives). Customers sign a Street Service Application ("SSA"), indicating their desire for natural gas service. As an SSA contains customer specific information, EGNB considers the completed forms to be confidential. However, a copy of a blank SSA is attached. EGNB does not require financial security from most customers as the customer is also investing their own capital to install natural gas equipment. However, for some commercial or industrial customers a security deposit may be required.

7.
   a. The requested system maps are attached.

   b. Please see the response to Board Interrogatory No. 3(a).

   c. In 2009, 115 customers were attached to the 2009 main projects at the time they were installed. EGNB does not track subsequent customer additions to mains based on the original mains project.

   d. Please see the response to 3. above regarding the manner in which the economics of an expansion project are justified. EGNB is unable to provide copies of the PRCRs for each expansion project in 2009 as they contain specific customer information which EGNB considers to be confidential.

8.
   a. Please see EGNB's response to Flakeboard Interrogatory No. 11(e) for the total number of customer attachments by class. Each of these attachments would have resulted in a meter addition. In 2009, approximately 93 of these attachments did not require a service line to be installed, as only the installation of a meter was required.

   b. EGNB does not track meter costs by rate class. Although there is some correlation between customer size and meter size, a customer's rate class does not determine the meter that is required by a customer. As a result, EGNB is unable to provide this information.

   c. EGNB does not track actual service additions by rate class. When such costs are recorded they are accounted for in projects based on the municipality the customer resides in, not their rate class. As a result, EGNB is unable to provide the requested information.

9.
   a. The following provides the requested comparison of the 2009 Construction Plan:

      Table 1:

2009 Forecasted Customer Additions (EGNB 2009 Construction Plan)								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	Total	Total Cumm.
Moncton	131	154	194	192	118	12	801	3763
Dieppe	26	26	39	37	23	2	153	713
Riverview	40	42	54	10	6	0	152	538
Fredericton	71	79	98	64	40	3	355	2593
Oromocto	3	4	5	6	3	0	21	1692
Saint John	52	44	54	98	60	5	313	1709
St. George	3	1	0	0	0	0	4	69
St. Stephen	19	10	3	4	2	0	38	201
Sackville	25	13	4	18	7	4	71	100
Total	**370**	**373**	**451**	**429**	**259**	**26**	**1,908**	**11,378**

2009 Actual Customer Attachments								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	TOTAL	Total Cumm.
Moncton	76	107	0	51	22	5	261	3199
Dieppe	12	56	0	6	8	1	83	632
Riverview	19	9	0	5	5	2	40	422
Fredericton	73	106	0	16	19	3	218	2431
Oromocto	3	9	0	6	4	0	22	1693
Saint John	73	17	0	42	56	10	199	1542
St. Stephen	6	0	0	1	1	0	8	167
St. George	0	0	0	1	0	0	1	62
Sackville	6	3	0	4	11	2	27	56
Total	**268**	**307**	**0**	**132**	**126**	**23**	**859**	**10,204**

2009 Actual Customer Attachments vs 2009 Forecasted Customer Attachments								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	TOTAL	Total Cumm.
Moncton	55	47	194	141	96	7	540	1025
Dieppe	14	-30	39	31	15	1	70	126
Riverview	21	33	54	5	1	-2	112	203
Fredericton	-2	-27	98	48	21	0	137	276
Oromocto	0	-5	5	0	-1	0	-1	-2
Saint John	-21	27	54	56	4	-5	114	249
St. Stephen	-3	1	0	-1	-1	0	-4	-5
St. George	19	10	3	3	2	0	37	55
Sackville	19	10	4	14	-4	2	44	69
Total	**102**	**66**	**451**	**297**	**133**	**3**	**1,049**	**1,996**

In 2009, EGNB attached 859 customers compared to a forecast of 1,908. The lower results were affected by the economic downturn which delayed decision making. Lower oil prices also created a lack of urgency as the average retail oil price in 2009 was 31% lower than 2008.

Table 2:

Rate Class	2009 Forecasted (GJ's)	2009 Actual (GJ's)	2009 Forecasted GJ vs 2009 Actual GJ's
Small General Service Residential Oil (SGSRO)	367,291	359,352	**7,939**
Small General Service Residential Electric (SGSRE)	216,312	180,315	**35,997**
Small General Service Commercial (SGSC)	354,073	253,589	**100,484**
General Service (GS)	1,212,259	1,062,813	**149,446**
Contract General Service (CGS)	1,146,112	1,011,111	**135,001**
Contract Large General Service (LFO)	2,203,330	1,366,938	**836,392**
Contract Large General Service (HFO)	905,957	973,681	**-67,724**
Off Peak Service (OPS)	5,684	3,061	**2,623**
Contract Large Volume Off Peak Service (CLVOPS)	26,396	0	**26,396**
Total	**6,437,414**	**5,210,860**	**1,226,554**

Actual throughput to forecast was affected by the lower attachment forecast.

Table 3:

Municipality	2009 Forecasted Mains (metres)	2009 Actual Mains (metres)	Variance Meters	2009 Forecasted Main Value ($)	*2009 Actual Main Value ($)	Variance Main $	2009 Forecasted Services Value ($)	*2009 Actual Services Value ($)	Variance Services $	2009 Forecasted Total ($)	2009 Actual Total ($)	Variance Total $
Moncton	21,296	8,400	12,896	1,376,427	476,050	900,377	1,340,285	457,786	882,499	2,716,712	933,836	1,782,876
Dieppe	4,070	3,910	160	263,057	217,981	45,076	253,377	168,423	84,954	516,434	386,404	130,030
Riverview	3,784	1,560	2,224	244,572	87,305	157,267	203,782	146,282	57,500	448,354	233,587	214,767
Sackville	2,486	3,020	-534	193,155	210,517	-17,362	141,240	47,291	93,949	334,395	257,808	76,587
Fredericton	13,266	10,930	2,336	1,884,489	1,327,820	556,669	594,966	443,991	150,975	2,479,455	1,771,811	707,644
Oromocto	550	950	-400	42,733	88,617	-45,884	36,751	63,826	-27,075	79,484	152,443	-72,959
Saint John	11,268	7,310	3,958	3,008,873	1,897,564	1,111,309	634,012	605,044	28,968	3,642,885	2,502,608	1,140,277
St. George	0	0	0	0	0	0	5,557	29,424	-23,867	5,557	29,424	-23,867
St. Stephen	0	140	-140	0	12,163	-12,163	60,020	5,970	54,050	60,020	18,133	41,887
Total	**56,720**	**36,220**	**20,500**	**$7,013,306**	**$4,318,017**	**$2,695,289**	**$3,269,990**	**$1,968,037**	**$1,301,953**	**$10,283,296**	**$6,286,054**	**$3,997,242**

A reduction in the amount of mains constructed relates primarily to reduced attachments and a strong focus on adding customers on main. The reduction in the number of services and related costs is the result of reduced customer attachments.

Table 4:

Fredericton Projects Identified So Far for 2009						
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**
3348-08	Hillcrest Drive Ext.	Sunny Brae	Forbes Drive	2	580	755
	Sunny Brae	Cliff Street	Hillcrest Drive Ext	2	170	
2090-10	Meadow Brook Drive	Cliff Street	Hillcrest Drive Ext	2	520	361
NA	Kimble Road	Aspendale Lane	Driveway to 605 Kimble	4	670	0
NA	Sunset Drive	83 Sunset Drive	51Sunset Drive	4	623	0
NA	Clements Drive	51Sunset Drive	641Clements Drive	4	1393	0
4008-08	Hanwell Road Project	Bishop Drive	Timothy Avenue South	6	4400	5235

Table 5:

Saint John Projects Identified So Far for 2009						
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**
3344-09	Clipper Passage	Existing	End	2	100	108
2966-08	Main Street West	Harding Street	TS Simms	4	140	66
2960-08	Carmarthen Street	Britain Street	223-225 Carmarthen	2	40	77
2965-08	Brunswick Place	Douglas Avenue	End	2	120	95
2954-08	First Street	Manawagonish Road	First Avenue	2	100	205
	First Avenue	First Street	Kierstead Road	2	25	
2958-08	St. James Street	179 St. James Street	168 St. James Street	2	40	208
2944-08	Bayside Drive	Edith Avenue	Park Avenue	2	130	152
3358-08	Woodhaven Drive	University Avenue	Noel Avenue	2	383	535
	Noel Avenue	Woodhaven Drive	End	2	150	
2948-09	Ravenscliffe Crescent	11Ravenscliffe Cres	49 Ravenscliffe Cres	2	60	56

Table 6:

Moncton Projects Identified So Far for 2009						
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**
NA	Checker Dr	Edinburgh Drive	45 Checker Dr	2	130	0
3343-09	Clover St	Weston Dr	Northumberland Dr.	2	250	1258
	Northumberland Dr.	Clover St	Hammond Ct	2	140	
	Hammond Ct	Northumberland Dr.	end	1.25	140	
	Thornhill Cres	Clover St	End	1.25	180	
	Weston Dr	Shediac Rd	Clover St	2	500	

In tables 4, 5 and 6, actual lengths of zero indicate that the project was not completed in 2009. The variance in length for WIP #4008-08 is the result of more main being constructed to service new customers. The variance in WIP #2090-10 and #2966-08 related to the actual route being significantly shorter than the proposed route in the 2009 Construction Plan. More pipe was installed for WIP # 2954-08 to capture future load potential. For WIP #2960-08 and #2958-08, more pipe was installed due to looping opportunities, improving overall system security. EGNB has not listed all other construction projects that occurred during 2009. These projects were undertaken to satisfy demand that wasn't committed at the time the construction plan was prepared.

b. Please see the response to 7a. above.

c. The forecasted capital cost spend of $10.28 million represents those costs related to the construction of mains and services (i.e. construction capital). The $16.61 million figure represents all of EGNB's capital spending. The actual spend for construction capital in 2009 was $8.7 million.

(1) In 2009, EGNB did not construct as much main as originally forecasted. The budget assumed the construction of 57 km of main for approximately $7.0 million. EGNB only constructed 36 km of main at a cost of $4.3 million.

(2) In 2009, EGNB did not construct as many services as originally forecasted. The budget assumed the construction of 1,908 services for approximately $3.3 million. EGNB only installed 732 services at a cost of $2.0 million.

(3) In 2009, EGNB assumed that 57 km of main would be constructed for $7.0 million ($123,000/km). The actual cost for constructing 36 km was $4.3 million ($119,000/km). EGNB does not track actual unit costs for mains by pipe size and municipality.

(4) In 2009, EGNB assumed that it would construct 1,908 services for a cost of $3.3 million ($1730/service). However, the actuals included the construction of 732 services for $2.0 million ($2732/service). EGNB does not track actual unit costs for services by rate class and municipality.

(5) EGNB does not believe there are any other factors that materially contribute to the difference between forecast and actual plant additions.

EGNB does not have any supporting documentation beyond the financial information provided in the responses above and its records in its accounting systems.

d.

(1) Please see the response to 6. above.

(2) In most cases, EGNB does not require a new customer to make a term commitment to receive service. Since the customer is also investing capital to install natural gas equipment, EGNB has a reasonable assurance that the customer will take service for an extended period of time. In cases where a significant expansion project may be required to reach a customer, a term commitment is required that supports the recovery of the capital employed.

(3) Based on a discussion with Jim Bracken, President, Heritage Gas, EGNB's expansion procedures are very similar to those of Heritage Gas. Both organizations require customer commitments before expanding their respective distribution systems. The profitability of the customers is also assessed in a similar manner. Heritage has two tests that it uses; a Mains Feasibility test for small scale expansions and a Community Feasibility Test for larger projects. This would be similar to EGNB's approach to smaller mains projects and larger expansion projects. In both cases, the economics for a larger expansion project may rely on reasonable expectations for customer signings and not solely on committed customers. For small scale projects, both organizations look at the economics of the expansion in terms of the profitability of the customer.

One difference between the two systems is that the economic justification of each Heritage Gas project is subject to scrutiny, whereas EGNB uses a portfolio approach. Heritage Gas' approach has led to complaints to the Nova Scotia Utility and Review Board from residents that are interested in having access to natural gas and are in reasonable proximity to the distribution system, yet cannot get service due to Heritage's inability to assess its expansion activities on a portfolio basis.

(4) EGNB does not have a formal policy regarding expanding infrastructure in response to customer commitments. It relies on standard practices that assess the economic feasibility of an expansion project.

(5) EGNB does not have any written internal communications between EGNB management and the EGNB sales force related to requiring customer commitments. This aspect of the sales role is addressed through training and ongoing coaching. The sales force is trained on the completion of an SSA, described in 6. above, as a demonstration of a customer's commitment.

10.

a. The following provides the requested comparison of the 2010 Construction Plan:
Table 1:

2010 Forecasted Customer Additions (EGNB 2010 Construction Plan)								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	Total	Total Cumm.
Moncton	91	84	110	99	101	20	505	3707
Dieppe	17	15	23	22	22	5	104	748
Riverview	38	35	45	4	4	0	126	552
Fredericton	43	52	66	48	48	9	266	2703
Oromocto	3	4	5	2	2	0	16	1709
Saint John	48	36	45	33	33	7	202	1751
St. George	2	2	0	0	0	0	4	193
St. Stephen	10	8	3	2	2	0	25	65
Sackville	13	9	3	0	0	0	25	83
Total	265	245	300	210	212	41	1,273	11,511

2010 Forecast Customer Attachments								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	TOTAL	Total Cumm.
Moncton	49	100	0	16	18	10	194	3393
Dieppe	6	72	0	7	3	5	93	725
Riverview	12	12	0	4	3	2	33	455
Fredericton	35	80	0	13	12	3	144	2575
Oromocto	0	18	0	3	4	2	27	1720
Saint John	22	32	0	18	25	9	106	1648
St. Stephen	2	0	0	1	2	0	5	172
St. George	0	0	0	0	1	1	2	64
Sackville	2	1	0	8	11	0	22	78
Unspecified Area	148	23	0	24	21	4	220	220
Total	276	338	0	94	100	36	846	11,050

2010 Forecast Customer Additions (EGNB 2010 Construction Plan) vs 2010 Forecast Customer Attachments								
	SGSRO	SGSRE	SGSNC	SGSC	GS	CGS	TOTAL	Total Cumm.
Moncton	42	-16	110	83	83	10	311	**314**
Dieppe	11	-57	23	15	19	0	11	**23**
Riverview	26	23	45	0	1	-2	93	**97**
Fredericton	8	-28	66	35	36	6	122	**128**
Oromocto	3	-14	5	-1	-2	-2	-11	**-11**
Saint John	26	4	45	15	8	-2	96	**103**
St. Stephen	0	2	0	-1	-2	0	-1	**21**
St. George	10	8	3	2	1	-1	23	**1**
Sackville	11	8	3	-8	-11	0	3	**5**
Total	137	-70	300	140	133	9	647	**681**

The 2010 forecast for customer attachments is 846 compared to an initial forecast of 1,273. The lower attachment forecast is primarily due to slower than expected economic recovery, as well as the negative media around EGNB rates creating uncertainty in the market and discouraging some potential customers from converting to gas.

Table 2:

Rate Class	2010 Construction Plan (GJ's)	2010 Forcast (GJ's)	2010 Construction Plan vs 2010 Forecast (GJ's)
Small General Service Residential Oil (SGSRO)	391,440	353,160	**38,280**
Small General Service Residential Electric (SGSRE)	214,673	188,164	**26,509**
Small General Service Commercial (SGSC)	313,737	283,589	**30,148**
General Service (GS)	1,275,587	979,494	**296,093**
Contract General Service (CGS)	1,221,612	1,068,110	**153,502**
Contract Large General Service (LFO)	1,519,886	1,410,235	**109,651**
Contract Large General Service (HFO)	904,285	1,049,105	**-144,820**
Off Peak Service (OPS)	4,110	8,209	**-4,099**
Contract Large Volume Off Peak Service (CLVOPS)	0	0	**0**
Total	**5,845,330**	**5,340,066**	**505,264**

Actual throughput to forecast was affected by the lower attachment forecast. A mild winter also contributed to the lower throughput.

2010 Construction Plan Costs vs. 2010 Forecast Costs

Municipality	2010 Construction Plan Mains (metres)	2010 Forecast Mains (metres)	Variance Meters	2010 Construction Plan Mains ($)	2010 Forecast Mains ($)	Variance Mains ($)	2010 Construction Plan Services ($)	2010 Forecast Services ($)	Variance ($)	2010 Construction Plan Total ($)	2010 Forecast Total ($)	Variance Total ($)
Moncton	6,204	7,700	-1,496	519,480	847,000	-327,520	1,196,667	482,672	713,995	1,716,147	1,329,672	386,475
Dieppe	1,650	2,200	-550	138,160	242,000	-103,840	253,556	231,384	22,172	391,716	473,384	-81,668
Riverview	2,200	2,800	-600	184,213	308,000	-123,787	224,126	82,104	142,022	408,339	390,104	18,235
Sackville	572	600	-28	51,796	60,000	-8,204	38,071	54,736	-16,665	89,867	114,736	-24,869
Fredericton	4,994	6,400	-1,406	452,215	640,000	-187,785	676,579	358,272	318,307	1,128,794	998,272	130,522
Oromocto	176	300	-124	15,937	30,000	-14,063	33,857	67,176	-33,319	49,794	97,176	-47,382
Saint John	3,124	3,900	-776	961,604	1,170,000	-208,396	665,962	263,728	402,234	1,627,566	1,433,728	193,838
St. George	0	0	0	0	0	0	7,321	4,976	2,345	7,321	4,976	2,345
St. Stephen	0	100	-100	0	17,500	-17,500	50,773	12,440	38,333	50,773	29,940	20,833
Unspecified Area	0	0	0	0	0	0	0	547,360	-547,360	0	547,360	-547,360
Total	**18,920**	**24,000**	**-5,080**	**$2,323,405**	**$3,314,500**	**-$991,095**	**$3,146,912**	**$2,104,848**	**$1,042,064**	**$5,470,317**	**$5,419,348**	**$50,969**

The increase in main construction is primarily due to more distribution mains being required to reach signed customers. The reduction in the number of services and related costs is the result of reduced customer attachments.

Table 4:

Saint John Projects Identified So Far for 2010							
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**	**Contractor Labor Costs**
2058-09	St. John Street	City Line Road	Ludlow Street	4	405	414	$86,248
2054-09	Cranston	Sixth Street	Thornborough	2	380	353	$113,339
2048-09	Sand Cove	Lawrence	Windsor	2	80	78	$17,398

Table 5:

Moncton Projects Identified So Far for 2010							
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**	**Contractor Labor Costs**
2083-09	Brydes Street	29 Brydes St	Bonaccord St	1.25	27	128	$25,485
	Bonaccord St	Brydges St	174	1.25	102		
3335-08	Acacia Drive	Lotus Row	End	2	195	1318	$92,849
	Lotus Row	Salisbury	Acacia Drive	2	325		
	Salisbury	Llangollen St	Lotus Row DR	4	765		
3407-09	Ryan St	1364 Ryan St	1460 Ryan St	4	300	716	$71,273
	Sunshine Dr	27 Sunshine	Augusta	2	550		
	Augusta	Sunshine Dr	Ryan St	2	530		

Table 6:

Dieppe Projects Identified So Far for 2010							
Project WIP#	**On**	**From**	**To**	**Pipe Size**	**Estimated Length (m)**	**Actual Length (m)**	**Contractor Labor Costs**
3419-10	Aviation Ave	Airport	End	4	1500	1312	$101,787

In tables 4, 5 and 6, the variance in length compared to the 2010 Construction Plan for WIP #3407-09 is the result of an alternate route selection. EGNB has not listed all other construction projects that are forecast to occur during 2010. These projects are to satisfy demand that wasn't committed at the time the construction plan was prepared.

b. Please see Tables 4 through 6 in a. above for costs by project. EGNB does not track new customer additions and throughput for each new main project. As a result, the requested information cannot be provided.

c. Please see the response to 3. above regarding the manner in which the economics of an expansion project are justified. EGNB is unable to provide copies of the PRCRs for each expansion project in 2010 as they contain specific customer information which EGNB considers to be confidential.

d. The following table provides the requested throughput information for the Construction Plan:

2010 Forecast Annualized Throughput GJ's Based on 2010 Construction Plan Customer Additions							
	SGSRO	**SGSRE**	**SGSNC**	**SGSC**	**GS**	**CGS**	**Total**
Moncton	10,374	9,576	12,540	19,305	90,900	66,000	**208,695**
Dieppe	1,938	1,710	2,622	4,290	19,800	16,500	**46,860**
Riverview	4,332	3,990	5,130	780	3,600	0	**17,832**
Fredericton	4,902	5,928	7,524	9,360	43,200	29,700	**100,614**
Oromocto	342	456	570	390	1,800	0	**3,558**
Saint John	5,472	4,104	5,130	6,435	29,700	23,100	**73,941**
St. George	228	228	0	0	0	0	**456**
St. Stephen	1,140	912	342	390	1,800	0	**4,584**
Sackville	1,482	1,026	342	0	0	0	**2,850**
Total	**30,210**	**27,930**	**34,200**	**40,950**	**190,800**	**135,300**	**459,390**

e. Please see the responses to a. above for costs by project. These projects are main construction projects only, so they do not have service costs associated with them. Please see the response to Public Intervenor Interrogatory No. 11(11) for 2010 forecast unit main costs by municipality. EGNB does not track new customer additions and throughput for each new main project. Rather an aggregate forecast is completed that identifies expected customer attachments and the associated throughput to be added both on existing main, as well as those attached from the installation of new mains.

11. Please see the response to AWL Interrogatory No. 17 for information regarding unit costs of mains and Board Interrogatory No. 15 (2(i)) for information regarding services.

To determine the unit costs for mains, EGNB first reviewed the estimated average mains costs for the last three years by community and pipe size.

2006 to 2009 Avgerage Main Costs $ / Metre									
	Fredericton	Oromocto	Moncton	Dieppe	Riverview	Saint John	St. George	St. Stephen	Sackville
2" Plastic	69.01	69.01	58.71	58.71	58.71	251.32	85.49	85.49	69.01
4" Plastic	109.18	109.18	84.46	84.46	84.46	289.43	164.80	164.80	109.18

A new construction contract came into effect in May, 2010 resulting in increased pricing for EGNB. For mains, the increase was 23%. As a result, the 2011 budgeted main line prices were developed by inflating the historic main costs by 23% to arrive at the unit prices as shown below:

2011 Budgeted Main Costs $ / Metre									
	Fredericton	Oromocto	Moncton	Dieppe	Riverview	Saint John	St. George	St. Stephen	Sackville
2" Plastic	84.88	84.88	72.21	72.21	72.21	309.12	105.15	105.15	84.88
4" Plastic	134.29	134.29	103.89	103.89	103.89	356.00	202.70	202.70	134.29

A similar approach was used for determining service line unit costs. The estimated average service costs for the past three years was reviewed:

2006 to 2009 Average Service Line Labor Costs									
Rate Class	Fredericton	Oromocto	Moncton	Dieppe	Riverview	Saint John	St. George	St. Stephen	Sackville
SGSRE	1,150	1,310	1,235	1,322	1,276	1,742	1,579	1,527	1,190
SGSRO	1,334	933	1,134	1,901	1,143	2,563	1,326	1,453	1,232
SGSNC	1,334	933	1,134	1,901	1,143	2,563	1,686	1,453	1,232
SGSC	1,526	4,434	1,622	2,283	1,779	2,216	2,273	2,273	2,112
GS	4,272	3,577	2,214	4,509	2,856	2,536	2,443	2,443	3,548
CGS	7,703	2,533	5,597	4,528	2,286	8,136	6,109	6,109	7,624

The 2010 budget service line costs to April 30 were determined by inflating the historic actuals by 5% to allow for extra work costs resulting from construction activities. Also, Fredericton average costs were used for Oromocto as it was determined that these costs better reflected expected costs going forward. The three year average costs for Moncton, Riverview and Dieppe were averaged together to develop budgeted 2010 costs for these areas. In May, these costs were inflated by 20% for an expected contractual increase in construction costs.

A new construction contract came into effect in May, 2010 resulting in increased pricing for EGNB. For services, the increase was 42%. As a result, the 2011 budgeted service line prices were developed by inflating the 2010 budget service costs by 42% to arrive at the unit prices as shown below:

2011 Budgeted Service Line Labor Costs									
Rate Class	Fredericton	Oromocto	Moncton	Dieppe	Riverview	Saint John	St. George	St. Stephen	Sackville
SGSRE	1,715	1,715	1,905	1,905	1,905	2,598	2,355	2,276	1,775
SGSRO	1,989	1,989	2,076	2,076	2,076	3,822	1,977	2,167	1,837
SGSNC	1,989	1,989	2,076	2,076	2,076	3,822	2,514	2,167	1,837
SGSC	2,275	2,275	2,825	2,825	2,825	3,304	3,389	3,389	3,149
GS	6,369	6,369	4,761	4,761	4,761	4,998	3,642	3,642	5,289
CGS	11,485	11,485	6,168	6,168	6,168	12,130	9,108	9,108	11,367

Reference: EGNB′s Installation Services Report.

Question:

1. With respect to EGNB's belief that installation services are an "as an integral part of its overall utility operations and the development of the gas market in New Brunswick."
   a. Please provide a citation to where in EGNB's proposal to the Province, EGNB states its opinion that installation services are (or could become) an integral part of overall utility operations and the development of the gas market in New Brunswick. Did Enbridge foresee that the unbundled model may fail?

   b. Please provide a citation to the specific section of the General Franchise Agreement that specifies installation services as being (or foresees them potentially becoming) an integral part of overall utility operations and the development of the gas market in New Brunswick. Please provide copies of the relevant sections and/or amendments.

   c. Please provide references to those sections of the legislation specifying that EGNB is to treat installation services as part of its regulated operations;

   d. Please provide a copy of the Board order directing EGNB to treat installation services as part of its regulated operations; and

   e. Please provide all findings of fact made by the Board relating to the competitiveness of the installation services market(s).

2. Is it the opinion of senior management that any activity EGNB perceives to be "an integral part of its overall utility operations" can be deemed a customer service and regulated by the Board if the Board so deems it appropriate? If so, on what basis?

3. Please provide a detailed list of all products and services that EGNB considers to be potentially part of its overall utility operations. Please include products and services that are currently offered (including ancillary products such as workmanship guarantees), as well as products and services that may be offered in the future. For example, if were to begin to offer customers energy efficiency services, could these be considered a part of EGNB's overall utility operations and hence subject to regulation? What other products and services would EGNB consider to be in the scope of what the Company may offer and what the Board may regulate? Please explain.

4. Please list all firms other than EGNB that currently perform or have in the past performed installation services in New Brunswick.

5. For each firm listed above, please provide the number of installations made by that firm in each community for each type of customer in each year from 2003 to 2010. Please also include the comparable data for EGNB by year, by type of customer, and by community. Please include the following communities:

- Dieppe,
- Fredericton,
- Moncton,
- Oromocto,
- Riverview,
- Sackville,
- Saint John,
- St. George and
- St.Stephen.

6. Please provide all information EGNB has regarding the other firms that perform installation services in New Brunswick. Please include financial information, pricing information, cost information, strategy and any other information EGNB has. If EGNB does not collect information on its competitors, please explain why not.

7. Please provide all analyses that EGNB has performed or reviewed relating to competition in the installation services market in New Brunswick since it began providing installation services.

8. Please list all asset accounts in rate base that contain investments or other assets related to installation services. Please provide all entries to those asset accounts for installation activities from 2003 through the present.

9. Please list all cost accounts that contain operating costs related to installation services. Please provide all entries to those cost accounts for installation activities from 2003 through the present.

10. Please provide copies of the “time and labour records” reviewed by EGNB and cited on the top of page 3 of the Installation Services report.

11. Please confirm that EGNB’s installation equipment inventories are carried at an imputed capital structure of 50% debt and 50% equity. Please confirm that the return on the imputed equity financing of equipment inventories is currently 13%.

12. Is EGNB aware of any other equipment supplier that is guaranteed a return of 13% on imputed equity?

13. Is EGNB aware of any other gas distributor (Greenfield or not) that includes installation services assets such as inventories in its regulated asset base and installation services costs in

its as regulated revenue requirement? If yes, please provide source documents and/or citations to the relevant docket numbers before the relevant regulatory commissions.

14. EGNB has experience separating out the costs and revenues of certain activities that EGNB performed on behalf of shareholders and not ratepayers, and hence appeared in the partnership financials but not the regulatory financials. Please explain why EGNB elected not to do this for installation services. Please provide supporting documents outlining the business case for this decision.

15. Did EGNB consider establishing an affiliate company to perform installation services? If yes, why did EGNB choose not to establish an affiliate? Please provide supporting documents outlining the business case for this decision. If no, why didn't EGNB consider establishing an affiliate? Please provide supporting documents outlining the business case for this decision.

16. Please describe the due diligence efforts performed by EGNB when it decided to enter into the installation services market. Please provide supporting documentation for EGNB's due diligence efforts.

17. Please provide copies of all legal, market and regulatory analysis of installation services performed or reviewed by EGNB in and around the time when EGNB first entered into the installation services market.

18. Please provide copies of all legal, market and regulatory analysis of installation services performed or reviewed by EGNB since EGNB entered into the installation services market.

19. Please provide all financial analyses performed by EGNB to support the 2005 change from offering customers a 5-year guarantee to a 1-year guarantee, as described in Note 1. Please show what EGNB's expectations were regarding projected effects of this change on the net revenues from installation services (and hence the reductions in the deferral account) for each year from 2006 to 2016. Please include year-by-year details comparing the costs of providing the guarantee with the revenues associated with the guarantee.

20. Please provide a copy of all promotional materials that EGNB currently provides to customers relating to its installation services business.

21. EGNB mentions that in 2008, it only performed installation services for 22% of the new attachments. Does EGNB consider this market share to be low? If so, why is it necessary for EGNB to stay in the installation services business?

22. Please explain why EGNB believes that a 22% market share "suggests" that its installation activities are not causing harm to the competitive market. In other words, why are a 22% market share for EGNB and unfair competition mutually exclusive? Please cite to all economics or antitrust treatises and legal precedents upon which EGNB bases its answer.

23. With regard to EGNB's statement on Page 4:

    "… in 2003 legislative changes were made to allow EGNB to provide system gas and installation services in a relatively unencumbered manner. EGNB was permitted to offer installation services without having to get prices approved by the Board. This recognized the competitive nature of these activities and the need to be able to offer competitive and responsive pricing. "

    a. Who "permitted" EGNB to offer installation services without having to get prices approved by the Board? If it was the Board, please provide a copy of the Board Order or correspondence from the Board.

    b. Is it EGNB's opinion that it has indeed offered responsive pricing to its customers? If so, please explain how?

    c. With respect to the statement on page 2 that "the Board's role should be similar to the role it plays vis-à-vis Gas Marketers" please clarify whether Gas Marketers have the right to make up any shortfalls from their competitive businesses in a Board-regulated revenue requirement?

    d. Please provide a schedule of prices showing the charges for each type of installation product and service offered by EGNB. Please provide these prices historically (going back to 2003 when EGNB first entered the market) and indicate how the prices for each product and service have changed over time. Please describe the trends in the competitive marketplace to which such price changes were responsive.

    e. Which officer within EGNB approves the EGNB pricing policy for installation products and services? Please provide the corporate governance document (policy or procedure) that gives that person authority to approve installation services pricing. Please also provide a copy of said pricing policy.

    f. What is EGNB's discounting policy? When are discounts permitted? Who approves discounts?

    g. Does EGNB have a price matching policy? If so, is this price matching policy advertised to the customer? Please provide supporting documentation.

24. With regard to EGNB's letter to the Board dated May 27, 2003, which is attached to the Installation Services report:

    a. Did EGNB receive confirmation from the Board that its proposal to treat installation services as regulated utility services was acceptable to the Board? If so, please provide supporting documentation.

    b. Is EGNB aware of any other regulated entity that provides services in an "unencumbered manner" (i.e., without price controls) yet still puts the business risks on ratepayers, or as EGNB puts it: "embarks in these activities with the clear expectation that any surplus or shortfall resulting from these activities will be integrated with the results of the distribution activity, i.e. added to or deducted from the deferral account."

c. Please provide a copy of EGNB's Customer Management Proposal presenting its proposed exit strategy for when it can no longer sell gas; as referenced on the top of Page 3 of the letter.

d. With respect to the statement on Page 2 that "Naturally, EGNB will keep separate accounting records that will allow it to report separately on these activities," please explain the steps that EGNB has taken to keep separate accounting records. Please provide a copy of the installation services general ledger for each year from 2003 through the present. Please also provide a copy of all internal policies relating to accounting for installation services.

e. Please provide a copy all enclosures associated with the letter, including the study of Dr. Pierre-Marcel Desjardins addressing EGNB's market power.

f. Please provide a copy of EGNB's business plan relating to the introduction of the Authorized Dealer Network mentioned on Pages 3 and 4.

g. With respect to the statement on Page 1 that legislative changes "*allow Enbridge Gas New Brunswick ("EGNB") to sell natural gas (as per regulation) and offer customer services without having to get prices approved by the Board*," please provide a copy of all legal opinions that EGNB relied upon in reaching these conclusions about the effects of the legislation. If no legal opinion was sought, why was no legal opinion sought? Did EGNB make these representations regarding the effects of the legislation to the Board without the advice of counsel?

Response:

1.

a. Section 4.1.3.7 of EGNB's Proposal to the Province states:

> "GNB proposes to provide gas distribution service through an unbundled pure utility which would not undertake activities such as commodity supply or provision of equipment and related services. These latter functions, while essential to successful development of a gas distribution system, are amenable to competition between unregulated service providers.
>
> In the event that unregulated third party service providers do not become established quickly enough, or are ineffective, GNB will arrange a fall back alternative to ensure that these essential functions are available as required to support development of the distribution system.
>
> One fallback alternative would be the provision of these functions through an unregulated affiliate of GNB which would coordinate closely with the regulated utility. *Another fallback alternative would be the provision of these functions directly*

by the regulated utility, in which case the profitability of these functions would be regulated under the cost of service model." (emphasis added)

EGNB believes that this clearly indicates that Enbridge foresaw that the unbundled model could fail.

b. Since an unbundled model was in place at the time the General Franchise Agreement was put in place, there are no provisions within the General Franchise Agreement addressing installation services.

c. EGNB is not aware of any legislation that directs EGNB to treat installation services as part of its regulated activities. Similarly, it is not aware of any legislation that precludes this.

d. EGNB is not aware of any Board order directing EGNB to treat installation services as part of its regulated operations. However, the Board has approved EGNB's financial results since 2004 in which installations services revenues and expenses were an integrated part of EGNB's regulated operations. In 2008, the Board requested additional information regarding installation services, but to date has not disallowed any costs associated with the provision of these services on an integrated basis.

e. EGNB is not aware of any finding of fact made by the Board relating to the competitiveness of the installation services market(s).

2. It is not the opinion of senior management "that any activity EGNB perceives to be "an integral part of its utility operations" can be deemed a customer service". There are many activities that EGNB believes are an integral part of its utility operations that it would not contemplate deeming, or would be considered by definition in the legislation, as a customer service.

3. EGNB would consider the following existing products and services to be part of its overall utility operations and subject to regulation:

   - Distribution of natural gas
   - Sales, installation and service of natural gas equipment
   - Equipment protection plans offered as part of installation and service activities
   - Agent billing and collection services
   - Commodity sales

   EGNB cannot speculate on what products or services it may offer in the future and how they may, or may not, be subject to regulation by the Board.

4. The following lists all firms that currently perform or have in the past performed natural gas installation services in New Brunswick that EGNB is aware of:

A-1 Gas Works
Air-Care
Alternatives
ATL Plumbing & Gas Fitting Inc
Atlantic HVAC Services
Atlantic Restaurant Equipment
Atlantica & Mechanical
Beaulieu Plumbing
Billings Mechanical
Black & McDonald Limited
Blakeny Fuels / Fundy Energy
Blue Flame Gas Products
Bob's Heating
Bruce Sutherland Associates
Brunswick Gas Services
BSM- Gilles Leblanc
Campbell's Plumbing
Carl Fox Plumbing
Carmichael Engineering Ltd.
CES Capitol Energy Services In
Classic Heating & Air Conditioning
Climate Control Tech. Services
Complete Heat
Conair Ventilation & Gas
Cosy Comfort Gas Heating
D&B Mechanical Ltd
Dependable Gas
Direct Energy
Doug Forgrave Plumbing
Doug White Plumbing & Heating
E. T. Mechanical
E.G. Stairs Ltd
E.W. Clowater & Sons(1981 Ltd)
Eastern Propane
Electrical & Refrigeration Ser
Energy Tech Sales & Services
Ermen Construction
Ermen Sam Plumbing & Heating
Expert Gas Services Ltd.
E-Zee Gas Services Ltd.
Fundy Gas Electric Services Lt
G&E Gas
Gary. C. Wilson Heating
Gas Guys
GASPRO Installers
Gas-Tek Services Ltd.
George Freeze Plumbing & Heat
George's Plumbing
Glowing Embers Stoves & Fire
Harbour City Propane Ltd.
Heat Source de Chaleur Inc.
Henderson Gas Works
Hogan's Mechanical
ICS State
Industrial Boiler-Tech Inc
Irving Oil Limited
Joe Corrigan Mechanical
JRI Mechanical
Keezer Home Energy Centre
Lawsons
Ledoux Mechanical
LeRoy's Heating Services Ltd.
MacEachern Ent. Ltd.
Madnat Gas Services
Maritime Fireplaces Ltd.
Master Mechanical
Maxon Gas Work Inc.
Moncton Plumbing
Moncton Propane
Northeastern Gas
Oral Crossman Contracting
Park Fuels
Pro Nat Installers
Quality Gas Services
Rebel Gas Services
Reg Plumbing & Heating
Salesse Heating
SBH Enterprises
Sica Ventilation Inc
Squires Home Improvements
Summit Energy
Sunpoke Energy Systems Ltd.
Superior Propane
T & M Gas Works
Thermal Mediums Inc
Thermech Systems Limited
Tymeg Services
Valley Home & Hearth
Vienneau Flooring
W.L. Falconer's Heating
Wilson's Heating Riverview

5. The requested information for 2009 and year-to date October 31, 2010 is attached. EGNB does not believe that information from 2003 to 2008 is relevant to this proceeding.

6. EGNB does not collect such information on other firms that perform installation services in New Brunswick. Such information would not typically be available as most businesses would consider it to be confidential.

7. EGNB has not performed or reviewed analyses related to competition in the installation services market in New Brunswick. However, as demonstrated in the response 5. above, EGNB has performed only 33% and 36% of the 2009 and 2010 year-to-date installations. EGNB believes this is an indicator that a competitive market for installations exists. The slight increase from previous years is attributable to EGNB temporarily taking over work for a residential new construction contractor that shut down its business.

8. EGNB considers all assets in rate base to be utility related. EGNB does not track investment in rate base according to the function of the asset, but the type of asset so that it is assigned the appropriate amortization rates. The one exception to this would be the Inventory for the Installation and Service business which is contained in a separate balance sheet account. EGNB does not believe it is appropriate or necessary to provide all entries from 2003 to the present for the Inventory account.

9. All cost accounts within EGNB are associated with cost centres and are directly assigned to the cost centre that drives their costs. Operating costs directly tied to the Installation and Services line of the business are captured and recorded to Cost of Goods Sold within EGNB's accounting records. EGNB does not believe it is appropriate or necessary to provide all entries from 2003 to the present for the Inventory account.

10. Copies of the time and labour records reviewed by EGNB and cited on the top of page 3 of the Installation Services report are attached. EGNB notes that the fitter names in the one report have been changed to identify a specific individual within EGNB.

11. Confirmed.

12. EGNB is not aware of any equipment supplier that is guaranteed a return of 13% on imputed equity. However, EGNB is also not aware of any equipment supplier whose return would be limited to 13% either.

13. EGNB has not conducted research regarding the treatment of installation and services assets, revenues and costs in regulated revenue requirements in other jurisdictions. EGNB is aware that prior to exiting these businesses in 2000, Enbridge Gas Distribution did include these activities in its utility results.

14. EGNB has established separate accounts for Installation Services revenues and direct Cost of Goods Sold. However, since Installation Services is considered an integral part of EGNB

these accounts are included in the regulatory financials. EGNB does not have any supporting documents for this decision.

15. Given that EGNB was requesting legislation amendments, EGNB did not consider establishing an affiliate at that time.

16. EGNB does not believe the requested information is relevant to this proceeding. The Board has accepted installation services as a part of the utility since the services commenced and has approved all costs up to and including 2008.

17. Please see the response to 16. above.

18. EGNB is not aware of any such analysis having been performed.

19. In 2005, EGNB discontinued offering a five year workmanship guarantee on its installation work, in favour of a one year workmanship warranty. At the time, it was noted by EGNB that the industry standard was to offer a one year warranty on workmanship. As well, EGNB was dealing with suppliers who were offering extended warranties on their equipment. As EGNB was moving in line with the industry standard, it did not conduct any analysis that would show the effects of this change on the net revenues of installation services from 2006 to 2016.

20. EGNB currently only provides promotional materials related to its residential and commercial protection plans. Copies of these materials are attached.

21. EGNB considers this to be a relatively low market share. As the contractor industry gains experience, expertise, and financial strength, it is expected that they will increase their share of the installations. However, it is necessary for EGNB to remain in the installation services business at this time in order to support the development of underserved markets and regions. The residential retrofit market is one example of a market that still requires EGNB's direct involvement, as EGNB continues to perform a significant number of those installations. Conversely, EGNB continues to place emphasis on the development of the contractor industry, and in fact has created and staffed a Channel Manager role, whose main objectives are to engage, train and develop programs in support of the contractor industry.

22. EGNB does not believe that its current share of the market is causing harm to the competitive market. EGNB's 22% market share in 2008 means that the overwhelming majority of the market was served by other market participants. Also, EGNB actively encourages the development of the contractor industry.

23.
    a. The government amended the Gas Distribution Act, 1999 to allow EGNB to provide these services without having to get prices approved by the Board.

    b. EGNB believes that it has offered responsive pricing to its customers. Natural gas solutions are developed on a labour, material and equipment "cost plus" basis which provides a small margin to cover overheads. This approach, as well as EGNB's material and equipment buying strategy helps provide low cost solutions to customers, while supporting the growth of the industry as a whole.

c. Gas Marketers do not have a regulated revenue requirement and, as such, do not have the right to make up any shortfalls through a regulated revenue requirement.

d. EGNB is unable to provide the requested schedule of prices as prices will vary by installation based on the specific circumstances associated with the installation. Also, since these services are offered in the competitive marketplace, EGNB considers this information to be commercially sensitive.

e. The Manager, Installation and Service approves the pricing strategy for installation products and services offered by EGNB in consultation with the Manager, Marketing and Sales. EGNB does not have a pricing policy document.

f. EGNB does not have a discounting policy. However, discounts, or acceptance of lower margins on installations, may occur in cases of innovative technology trials, where new equipment is being market tested, or in cases of customer discontent surrounding installation or equipment performance. The Manager, Installation and Service approves any such discounting.

g. EGNB does not have a price matching policy.

24.

a. EGNB is not aware of any response being received to its May 27, 2003 letter. However, this is not unexpected, as the letter was intended to document discussion that occurred at a May 26, 2003 meeting. EGNB believes that if it had not accurately reflected the discussion, a response would have been provided.

b. EGNB has not conducted any research into the manner in which other utilities may provide such services. EGNB is in a unique situation where it is still developing the market, which requires regulatory approaches that support the growth and development of EGNB's customer base.

c. EGNB has not prepared the Customer Management Proposal referenced in the letter. At the time the letter was written, the legislation contemplated EGNB filing with the Board a Customer Management Proposal by December 31, 2007. Since that time the legislation has been changed to remove any sunset date. Given that a Customer Management Proposal is only required if EGNB were to decide it will no longer sell gas to customers, it has not prepared such a proposal as it has no intention of ceasing to sell gas to customers.

d. Operating costs directly associated with the installation services activities are captured and recorded to cost of goods sold within EGNB's accounting records. Similarly, installation services are captured separately with EGNB's accounting records. A separate general ledger does not exist, nor is it required, for installation services activities as these activities are integrated in the regulated utility operations. There are no internal policies specifically dealing with installation services accounting.

e. A copy of the Dr. Pierre-Marcel Desjardins study is attached. This was the only enclosure with the May 27, 2003 letter.

f. EGNB did not have a formal business plan relating to the introduction of the Authorized Dealer Network as it expected to duplicate what had been done in Ontario.

g. EGNB did not obtain any legal opinions on the changes to the legislation. EGNB had worked with the government over a period of time to effect changes to the legislation and as a result was quite clear on what the changes to the legislation were intended to permit.

Reference: EGNB′s Gas Purchasing Plan.

Question:

1. Does EGNB believe that EGNB's Gas Purchasing Plan advances the objective of providing security of supply to its customers? If so, on what basis? Please provide documentation (studies, memoranda, reports) to support EGNB's opinion in this regard.

2. Would security of supply be at risk if EGNB did not enter into any forward contracts for the purchase of commodity gas? Please provide documentation (studies, memoranda, reports) to support EGNB's opinion in this regard.

3. EGNB's third principle underlying the Gas Purchasing Plan is to "minimize EGNB's financial exposure." EGNB also states that the plan is designed to minimize financial risk to its customers. Please list each of the risks EGNB perceives to exist in the supply of commodity gas and indicate for each risk whether it is customers or EGNB who bear the risk. Please provide an explanation and include at least the following risks, as well as the other risks perceived by EGNB to exist:

    a. market price risk
    b. basis price risk
    c. variable load shape risk
    d. balancing cost risk
    e. execution risk
    f. collateral cost risk
    g. liquidity risk
    h. counterparty credit risk
    i. settlement risk
    j. risk that premium above index embedded in supply contract paid is above the prevailing premium in the market

4. Please demonstrate how EGNB's Gas Purchasing Plan minimizes, for EGNB and/or for customers, each risk cited in EGNB's answer to 3. above.

5. Please provide a list of all gas commodity procurement strategies evaluated by EGNB prior to selecting its preferred procurement strategy.

6. Please demonstrate how EGNB's preferred procurement strategy better advances its three guiding principles than the other procurement strategies evaluated by EGNB.

7. Please explain in detail how EGNB's Gas Purchasing Plan advances the goal of being able to offer a price that is reflective of market conditions in Atlantic Canada.

8. Does EGNB believe that the spot price at Dracut, Massachusetts is reflective of market conditions in Atlantic Canada? Please explain.

9. Does EGNB believe that the spot price at Tetco-M3 is reflective of market conditions in Atlantic Canada? Please explain.

10. Does EGNB believe that the spot price at Transco Zone 6 is reflective of market conditions in Atlantic Canada? Please explain.

11. With respect to EGNB's statement that: "The selected Boston trading points are Dracut, Transco Zone 6, and Tetco M3" Given the physical configurations of the Tetco and Transco pipelines, please describe the risks that the prices for Transco Zone 6, and Tetco M3 could diverge from prices at delivery points in the Boston area.

12. How does EGNB evaluate whether to use a daily or monthly index when buying index gas? Please provide a list of pros and cons for each. Please justify answer with supporting analyses, reports and other documents, as appropriate. Please show how the settlement terms of EGNB's current supply contracts are consistent with this rationale.

13. Please state whether the gas volumes cited in Attachment A are intended to be measured at the retail meter, or at an alternative location. If an alternative location, please specify which one.

14. Please state whether the gas volumes shown in the Regulatory Financial Statements for 2009 are intended to be measured at the retail meter, or at an alternative location. If an alternative location, please specify which one.

15. Please explain how EGNB converts quantities required at the customer meter to procurement volumes needed in the wholesale gas market. Please provide supporting documentation to support the calculations.

16. The total market forecast value included in Attachment A for 2011 is greater than the amount included in the 2011 budget. Please reconcile these two forecasts. Which forecast is EGNB relying on for planning purposes?

17. Please specify the policies and procedures EGNB has in place to modify its gas purchases in response to changes in its forecast demands. Please provide copies of all relevant policies and procedures, as well as any other supporting documentation.

18. Please specify how many times since EGNB began purchasing gas EGNB has exited any of its gas commodity positions when it became clear that EGNB had excess purchase volumes.

19. Please provide the forecast gas volumes shown in Attachment A on a daily basis by type of product and by rate class.

20. Please provide all analyses performed by EGNB or an EGNB affiliate related to the variability of the forecast commodity gas sales volumes referred to in 19. above. Please explain in detail how EGNB manages the various sources of variability (weather, economic activity, customers' switching to non-EGNB suppliers, customers' switching to another fuel source, and so forth) and how those variability risks are addressed in its commodity gas purchasing strategy.

21. Please provide the actual historical EGNB commodity sales volumes by day, by product and by rate class from 2003 through the present.

22. Please fill in the tables below with respect to gas quantity forecasts and gas forward purchases for each month during the time period January 2003 through the present.

Table 1: Forecast Volumes

	Forecast from Gas Purchasing Plan (GJ)			Forecast from Annual Budget (GJ)			Actual Throughput (GJ)		
Month	Total market	EUG	Alternative Offer	Total market	EUG	Alternative Offer	Total market	EUG	Alternative Offer

Table 2: Purchase Volumes

Month	Purchase Anticipated in Gas Purchasing Plan (GJ)		Purchase Anticipated in Annual Budget (GJ)		Actual Purchase (GJ)	
	EUG	Alternative Offer	EUG	Alternative Offer	EUG	Alternative Offer

23. The summary of supply contracts in Attachment A shows a total contracted volume of 2.184 TJ for 2009, whereas the Commodity Sales Report shows customer volumes of only 2.093 TJ. On what date did EGNB realize it was overcontracted for 2009?

24. The summary of supply contracts in Attachment A shows a total supply position of 10,550 GJ/d for December 2009 and 8,440 GJ/d for November 2009. For each day in November and December 2009, please provide the EUG standard offer customer volume, Alternative Offer customer volume, and aggregate EGNB commodity customer volume, where the aggregate is merely the sum of EUG standard offer and Alternative Offer volumes. Please provide the net short or net long position relative to the contract quantity on a day-by-day basis for this period.

25. Please explain EGNB's strategy for liquidating its excess commodity purchases.

26. Please describe how EGNB evaluated the options available to it for managing its excess contract position, including, for example, liquidating in the forward market with an offsetting sale, negotiating contract quantity reductions with EGNB's counterparties, and any other options considered by EGNB. Please describe the effect on EGNB's cash flow from each alternative and explain the considerations that drove EGNB to choose one of these options over the others.

27. Table 2 of Attachment A shows two seasonal Block 2 contracts expiring in March 2010. Please specify whether EGNB has replaced those contracts for the winter 2010/2011 season? For the 2011/2012 season? For the 2012/2013 season? For the 2013/2014 season? If so, please specify the contract quantities and delivery terms and for the new contracts.

28. If EGNB has replaced the contracts cited in 27. above, please demonstrate how the new contracts entered into meet EGNB's daily gas needs by product and by rate class. Are they flat for the whole season, or shaped to the monthly load?

29. Please provide copies of all load and resource analyses performed by EGNB at the time it entered into the 7-year Block 1 contract. Please demonstrate how that contract was forecast to meet EGNB's daily gas needs by product and by rate class at the time it was entered into.

30. With respect to EGNB's efforts to secure storage on behalf of its commodity customers.
    a. Please provide a detailed explanation of EGNB's efforts.
    b. Please provide a copy of all written analyses related to storage prepared or reviewed by EGNB.
    c. Please describe all negotiations in which EGNB is or has been engaged.
    d. Please indicate whether EGNB has signed any contracts related to storage. If so, please provide a copy of the contract.
    e. Please provide copies of all press releases and/or press articles related to EGNB's efforts to secure storage on behalf of its gas commodity customers.

31. Please provide a 90% confidence interval for EGNB's commodity gas volumes for each month from December 2010 through December 2014. Please specify in detail all assumptions made when calculating the confidence interval.

32. Please show the net long or net short positions for each month at the low and high end of the confidence interval calculated in Question 31 above, based on the supply contracts EGNB currently has entered into. Please also specify those supply contracts that EGNB expects to enter into for those delivery periods and provide a comparable analysis of the net short or net long for each month based on how EGNB expects to fill its needs.

33. Please provide a value-at-risk analysis of EGNB's existing supply portfolio and EGNB's customer obligations for each month from December 2010 through December 2014. Please specify in detail all assumptions made when calculating value at risk.

34. In light of the value-at-risk analysis shown in 33. above, please comment on the financial risks to EGNB and to its customers for each month between December 2010 and December 2014.

35. Please provide all analyses performed by EGNB or reviewed by EGNB of the effects of exploration and production in the Marcellus shale on prices in the Northeast United States.

36. Please list the new pipelines that are being planned to bring the Marcellus shale gas to load centres. Please specify the status of each pipeline (in planning stage, permitting stage, under construction) and the projected commercial operation dates.

37. Please describe the projected effects of the developments cited in 35. and 36 above on prices at Dracut, MA, Tetco-M3, Transco Zone 6 (NY) and Transco Zone-6 (non-NY). Please specify the timing of the projected price effects.

38. Please describe how the developments price cited in 35. and 36 above will affect security of supply for EGNB's gas commodity customers.

39. Please describe how the developments price cited in Questions 35 and 36 above affect EGNB's commodity gas procurement strategy on behalf of its commodity gas customers.

Response:

1. EGNB believes that its Gas Purchasing Plan advances the objective of providing security of supply to its customers by entering into longer term commitments and staggering contract periods as this ensures ongoing market participation of natural gas sellers into New Brunswick. Since EGNB believes this conclusion is self-evident, it does not have any documentation that supports this opinion.

2. While EGNB does not have any specific documentation to provide, EGNB believes that security of supply would be at risk if EGNB did not enter into forward contracts for gas. The basis for this opinion rests with the general understanding that the natural gas market in Atlantic Canada is comprised of a limited number of market participants on both the supply and demand side of the equation. By committing to longer term gas purchase agreements, EGNB demonstrates to market participants, its intention to remain engaged as a market purchaser in Atlantic Canada, thus contributing to maintaining an active natural gas market.

   While the absence of these commitments by EGNB would not necessarily leave the market without access to gas supply, the lack of an active natural gas market in New Brunswick may make it more difficult for parties to access supply on reasonable pricing terms.

3. EGNB believes that all of the risks identified, with the exception of execution risk, are generally borne by EUG customers in the near term. The use of the PGVA captures any price variations that may occur due to the risks identified, which is then expected to be recovered from EUG customers. However, over the longer term, EGNB bears the risk that that the realization of the individual risks results in a higher EUG price. If this situation occurs, under market-based rates EGNB would have to have lower delivery rates to continue to deliver target savings levels. These lower delivery rates result in increased contributions to the Deferral Account. Any increase in the size of the Deferral Account increases EGNB's risk that it will ultimately be able to recover the full Deferral Account. Also, if EUG prices increase significantly due to the realization of the identified risks, EGNB bears the risk that EUG customers will acquire their gas supply from a marketer at the end of their contract term. A significant exodus from EUG would make it increasingly difficult for EGNB to recover the PGVA balance without further erosion of its EUG customer base. This would compound the Deferral Account risk identified above, while also increasing the risk that EGNB may not be able to ultimately recover the PGVA balance due to the loss of EUG customers.

   In the case of execution risk, EGNB believes that it bears this risk. By entering into longer term gas purchase contracts, EGNB could be faced with purchase obligations without having customer commitments to purchase gas (i.e. all customers supplied by other marketers). While EGNB would have the opportunity to resell this gas into the market, there is no guarantee that EGNB would fully recover the price paid for the gas.

   EGNB believes there is one additional risk that has not been identified, which is regulatory risk. This risk is borne by EGNB. EGNB's commodity purchases and sales are subject to review by the Board. To the extent that the Board determined that EGNB had not acted appropriately in the provision of its commodity services, EGNB would be at risk for any ruling of the Board related to this.

4. EGNB's Gas Purchasing Plan does not serve the business as a risk management document. However, through the execution of the Gas Purchasing Plan and the use of its guiding principles, EGNB may simultaneously reduce the risks to itself and its customers. As described in the answer to 3. above, EGNB manages its business risks through such means as its contracting practices, credit/security practices, operational practices and product pricing practices. Ultimately, the effectiveness of EGNB's Gas Purchasing Plan would be demonstrated through the growth of the New Brunswick natural gas industry, while maintaining a minimal PGVA balance.

5. EGNB did not evaluate a list of formal commodity procurement strategies prior to selecting its preferred strategy. EGNB's Gas Purchasing Plan originated from the recognition of the unique market conditions which exist in Atlantic Canada (i.e. limited infrastructure, limited market participants and limited supply sources). The outcome of this recognition was a plan which would best address these market limitations.

6. EGNB is unable to demonstrate how its procurement strategy better advances its three guiding principles as no other procurement strategies were evaluated.

7. EGNB's Gas Purchasing Plan offers gas pricing reflective of market conditions in the following ways:
    - Diversity of Supply – By maintaining active contracts with existing counterparties and fostering relationships with new market participants, EGNB will help sustain a competitive environment for the purchase and sale of natural gas in Atlantic Canada.
    - Staggered Contract Terms –By having different start and end dates for various contracts, EGNB will be entering into agreements at different points in time, both throughout a calendar year and over the course of market development to ensure that it reduces the impacts of seasonal volatility and economic volatility on EGNB's gas portfolio, while also integrating current market dynamics into its portfolio.
    - Variety of Price Indices – For EGNB, it is important to seek liquid and stable points to contract gas purchases at. While choosing more than one trading point will increase the chance of basis gap between the contract price and a reflective market price, this can be offset if this point has increased liquidity, which inherently reduces volatility. Also, by using both daily and monthly index pricing, EGNB can further diversify these indices, thus lessening the impact of trading point volatility to EGNB's gas portfolio.

8. EGNB believes that the spot price at Dracut, Massachusetts is reasonably reflective of market conditions in Atlantic Canada. Since the majority of gas supplied into the Dracut market is sourced from Atlantic Canada through the Maritimes & Northeast Pipeline ("M&NP"), the pricing at Dracut reasonably reflects the value that suppliers moving gas through M&NP are able to obtain. In general, but not in all cases, the market price of spot gas in Atlantic Canada is equal to the difference between the market price at Dracut and the cost of transportation from Atlantic Canada to Dracut.

9. EGNB believes that a reasonable relationship exists between the spot price at Tetco-M3 and the market price of spot gas purchased in Atlantic Canada. This relationship exists because there is a physical (pipeline) connection between the Tetco-M3 trading point and Atlantic Canada.

    Throughout North America, there is a pricing relationship between all trading points (i.e. interconnecting points between two or more pipelines where custody of gas can change hands from one counterparty to another) commonly referred to as a "basis differential" or "basis". This value is relative to a spot price at a central trading location in North America know as "Henry Hub", located in Louisiana. While there is a relationship between the "basis" values across North America and the associated costs of transportation throughout all of the interconnected pipelines in North America, the "basis" values do not equal the transportation costs. Depending on localized supply/demand economics, the "basis" value for any trading point in North America could trade at a discount or premium to the actual cost associated with moving gas from supply source (wellhead) to demand source (market).

    Given Tetco-M3's proximity and physical connection to the Atlantic Canadian market, EGNB believes that the spot price at Tetco-M3 will be reasonably reflective of pricing options for Atlantic Canadian natural gas.

10. EGNB believes that a reasonable relationship exists between the spot price at Transco Zone 6 and the market price of spot gas purchased in Atlantic Canada for the same reasons articulated in 9. above. There is a physical connection between the Transco Zone 6 trading point and Atlantic Canada.

11. There are risks that Transco Zone 6 and Tetco M3 could diverge from prices at Dracut due to the impact of local supply/demand fundamentals. EGNB would expect to see this divergence occur on an intra-month basis, when these fundamentals will have the most volatility. There is less risk of divergence on a monthly basis, as the trading points are connected by pipeline capacity and the markets will tend to move towards equilibrium.

12. EGNB evaluates its use of daily or monthly indices based on the term over which the contracted volume will remain consistent. If the volume of gas purchased will not vary on a daily basis throughout a contract month, EGNB generally chooses to purchase at the monthly index price. The primary reasoning for this is that the contract price is established at the start of the month rather than the end of the month, reducing the risk of market volatility from start to end of month.

13. The volumes cited in Table 1 – Forecast Customer Additions & Volumetric Requirements of Attachment A are intended to be measured at the retail meter, or the customer meter, as that is the only basis by which EGNB can distinguish the market segment being served.

14. Gas volumes shown in Note 5 of the Regulatory Financial Statements for 2009 are measured at the retail meter, or the customer meter, as that is the only basis by which EGNB can distinguish the market segment being served.

15. EGNB considers the aggregate quantity of gas required at the customer meter to equal the procurement volumes needed in the wholesale gas market. As a result, no conversion is required.

16. EGNB’s 6,205 TJ forecast of the total market in the Gas Purchasing Plan is 391 TJ greater than the 5,814 TJ included in the 2011 budget. This variance is primarily due to updated projections of customer attachments and existing customer consumption between March and October 2010 based on updated market and forecast information available when the budget was prepared. For planning and procurement purposes, EGNB always relies on its most recent forecast information.

17. EGNB does not have set policies outside the Gas Purchasing Plan that govern how and when modifications are formally made to procurement volumes. Discussion between the Gas Supply Analyst and the appropriate senior managers occurs prior to contracting for supply in response to changes in demand.

18. Since EGNB began purchasing gas, it has managed purchases and sales as a combined portfolio, rather than as a series of individual contracts. To clarify, EGNB considers exiting a gas commodity position to be the same as selling excess gas back to the counterparty it is

purchased from at prevailing market rates. EGNB has not restricted excess gas sale activities to any one party based on the origin of the gas. Rather EGNB has been in a constant state of either buying or selling volumes on a daily basis to meet its market demand.

19. EGNB is unable to provide the requested information as it does not develop its forecast on a daily basis by product and rate class.

20. Neither EGNB nor an EGNB affiliate has performed specific analysis related to the variability of the forecast commodity gas sales volumes referred to in 19. above. EGNB, as provided in the Gas Purchasing Plan, uses guiding principles as an elastic approach to achieving its objective of procuring optimal supply of natural gas to meet its market requirements. EGNB acknowledges that there are various sources of variability associated with long term forecasting. For this reason, EGNB prefers to take this operational approach.

21. EGNB is unable to provide the requested information as it requires information at an individual customer level, which is only collected on a monthly basis through a meter reading. Also, if this information were available, EGNB would not consider the information from 2003 to 2008 to be relevant for this proceeding as the Board has already reviewed and rendered decisions on EGNB commodity sales activities for these years.

22. Please see the requested information for 2009 and year-to-date 2010. Since EGNB's previous Gas Purchasing Plan did not include a forecast for 2009 consumption and the updated Gas Purchasing Plan is addresses the years 2010 to 2014, EGNB is unable to provide a forecast from the Gas Purchasing Plan. EGNB does not believe information for the years 2003 to 2008 is relevant to this proceeding as the Board has already reviewed and rendered decisions on EGNB commodity sales activities for these years.

Table 1: Forecast Volumes

	Forecast from Annual Budget (GJ)			Actual Throughput (GJ)		
Month	Total market	EUG	Alternative Offer	Total market	EUG	Alternative Offer
Jan-09	857,638	212,469	113,213	847,115	186,641	142,315
Feb-09	818,564	186,332	109,979	682,723	147,562	120,097
Mar-09	749,483	158,028	114,412	610,716	115,712	98,031
Apr-09	598,361	107,058	98,044	455,909	70,124	108,068
May-09	401,517	62,280	83,865	286,175	52,630	81,218
Jun-09	293,027	32,449	57,313	198,058	16,097	50,213
Jul-09	275,623	29,556	57,562	163,631	19,478	46,862
Aug-09	276,243	30,547	55,814	208,293	11,033	54,747
Sep-09	297,361	34,304	58,232	220,047	22,033	54,064
Oct-09	482,557	81,907	81,178	391,401	27,070	92,692
Nov-09	599,902	121,167	95,731	480,323	115,475	138,349
Dec-09	787,139	193,067	109,211	666,470	151,517	171,086
Jan-10	842,335	169,191	120,582	842,185	153,819	230,997
Feb-10	804,651	169,809	110,008	633,722	113,923	199,243
Mar-10	686,283	131,316	103,832	646,168	111,673	197,192
Apr-10	505,352	80,973	94,900	409,016	47,009	148,866
May-10	331,492	45,325	77,022	303,934	29,823	99,050
Jun-10	226,310	24,932	46,962	571,202	127,780	58,715
Jul-10	215,863	23,995	46,762	(178,708)	(103,709)	52,310
Aug-10	217,558	23,637	46,035	176,353	5,895	59,490
Sep-10	247,130	26,589	47,654	243,952	(23,063)	68,149
Oct-10	394,605	55,786	80,597	378,825	51,645	118,592

Table 2: Purchase Volumes

Month	Purchase Anticipated in Annual Budget (GJ)		Actual Purchase (GJ)	
	EUG	Alternative Offer	EUG	Alternative Offer
Jan-09	163,927	113,213	185,459	142,315
Feb-09	140,341	109,979	170,066	120,097
Mar-09	147,228	114,412	205,625	98,031
Apr-09	60,206	98,044	94,167	108,068
May-09	79,660	83,865	124,178	81,218
Jun-09	100,937	57,313	144,231	50,213
Jul-09	105,963	57,562	151,392	46,862
Aug-09	107,711	55,814	145,466	54,747
Sep-09	100,018	58,232	145,210	54,064
Oct-09	82,347	81,178	111,729	92,692
Nov-09	157,469	95,731	155,120	138,349
Dec-09	159,435	109,211	138,508	171,086
Jan-10	141,058	120,582	72,694	230,997
Feb-10	137,512	110,008	85,998	199,243
Mar-10	157,808	103,832	112,816	197,192
Apr-10	63,350	94,900	47,948	148,866
May-10	86,503	77,022	103,878	99,050
Jun-10	111,288	46,962	133,466	58,715
Jul-10	116,763	46,762	145,196	52,310
Aug-10	117,490	46,035	143,506	59,490
Sep-10	110,596	47,654	129,627	68,149
Oct-10	82,928	80,597	79,592	118,592

23. EGNB did not, at any point in 2009, consider itself to be over contracted. In total for 2009, EGNB purchased net excess volumes of 91 TJ (4%), which converts to an average of 250 GJ/d of excess sales. EGNB expects to have a certain level of excess volumes that it will have to sell during the summer months as this allows for a greater portion of EGNB's winter needs to be met through an annual contract, rather than a seasonal contract that will typically attract a premium price.

24. EGNB does not distinguish between standard offer and alternative offer customers during daily operations for supplying gas to customers. Also, EGNB does not have actual consumption on a daily basis as metering reading information is only collected monthly. For managing gas supply, EGNB is allocated a volume of the total volumes received into the distribution system at the various city gates. This information is used for measuring supply and demand operationally between different gas suppliers. The following table provides the requested information on this basis:

Date	Contracted Volume	Total Consumption	Net Position
November 1, 2009	8,440	5,497	2,943
November 2, 2009	8,440	7,743	697
November 3, 2009	8,440	7,730	710
November 4, 2009	8,440	9,452	(1,012)
November 5, 2009	8,440	8,809	(369)
November 6, 2009	8,440	8,361	79
November 7, 2009	8,440	7,264	1,176
November 8, 2009	8,440	8,221	219
November 9, 2009	8,440	6,983	1,457
November 10, 2009	8,440	7,411	1,029
November 11, 2009	8,440	6,445	1,995
November 12, 2009	8,440	7,061	1,379
November 13, 2009	8,440	6,484	1,956
November 14, 2009	8,440	4,982	3,458
November 15, 2009	8,440	4,612	3,828
November 16, 2009	8,440	8,348	92
November 17, 2009	8,440	9,895	(1,455)
November 18, 2009	8,440	8,754	(314)
November 19, 2009	8,440	7,198	1,242
November 20, 2009	8,440	4,878	3,562
November 21, 2009	8,440	5,083	3,357
November 22, 2009	8,440	6,560	1,880
November 23, 2009	8,440	9,870	(1,430)
November 24, 2009	8,440	9,103	(663)
November 25, 2009	8,440	8,758	(318)
November 26, 2009	8,440	7,900	540
November 27, 2009	8,440	5,496	2,944
November 28, 2009	8,440	6,016	2,424
November 29, 2009	8,440	7,737	703
November 30, 2009	8,440	10,409	(1,969)

Date	Contracted Volume	Total Consumption	Net Position
December 1, 2009	10,550	11,369	(819)
December 2, 2009	10,550	9,897	653
December 3, 2009	10,550	9,419	1,131
December 4, 2009	10,550	6,501	4,049
December 5, 2009	10,550	7,215	3,335
December 6, 2009	10,550	9,087	1,463
December 7, 2009	10,550	12,500	(1,950)
December 8, 2009	10,550	13,190	(2,640)
December 9, 2009	10,550	12,760	(2,210)
December 10, 2009	10,550	11,425	(875)
December 11, 2009	10,550	12,049	(1,499)
December 12, 2009	10,550	11,434	(884)
December 13, 2009	10,550	9,415	1,135
December 14, 2009	10,550	11,746	(1,196)
December 15, 2009	10,550	11,810	(1,260)
December 16, 2009	10,550	15,724	(5,174)
December 17, 2009	10,550	17,267	(6,717)
December 18, 2009	10,550	13,490	(2,940)
December 19, 2009	10,550	11,058	(508)
December 20, 2009	10,550	10,689	(139)
December 21, 2009	10,550	12,684	(2,134)
December 22, 2009	10,550	11,513	(963)
December 23, 2009	10,550	11,186	(636)
December 24, 2009	10,550	8,519	2,031
December 25, 2009	10,550	8,834	1,716
December 26, 2009	10,550	8,436	2,114
December 27, 2009	10,550	7,745	2,805
December 28, 2009	10,550	8,075	2,475
December 29, 2009	10,550	12,349	(1,799)
December 30, 2009	10,550	13,462	(2,912)
December 31, 2009	10,550	11,262	(712)
Total	580,250	565,170	15,080

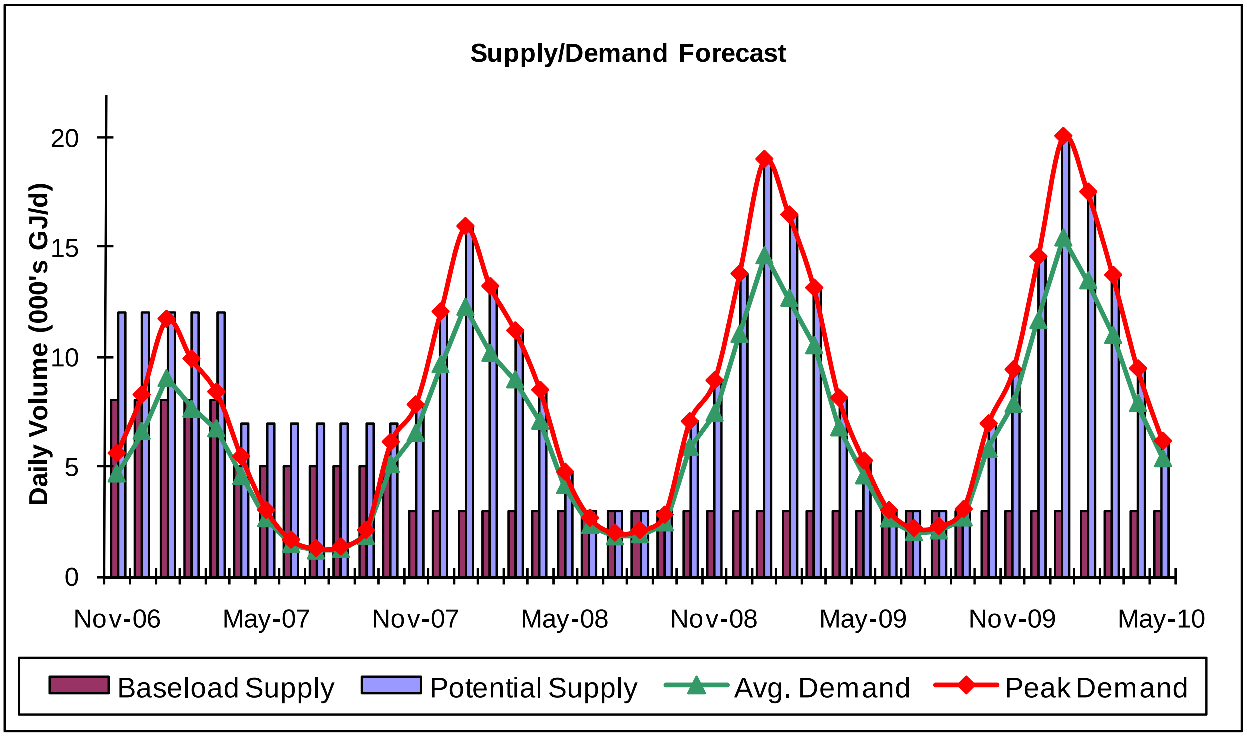
25. EGNB contracts for the sale of its excess volumes as part of the overall Gas Purchasing Plan, using the Plan For Procuring Gas as outlined on page 2 of the Gas Purchasing Plan. During 2009, EGNB sold 95% of its excess volumes to one counterparty.

26. EGNB did not evaluate options such as liquidating positions, negotiating reduced quantities or other options, as it did not, at any point in 2009 consider itself to be in an over contracted position that may require evaluating such options.

27. EGNB has entered into a gas supply contract for 6,330 GJ/d for the term November 1, 2010 through March 31, 2011 (5 months) and is currently exploring further contracting options beyond March 31, 2011 which consider gas supply over a longer term. At this point however, EGNB has not contracted for winter volumes beyond March 31, 2011.

28. EGNB's new contract, described in 27. above, is flat for the whole season, and is not expected to meet 100% of EGNB's daily gas needs over this term. EGNB expects to meet the remainder of its daily gas needs by making spot purchases when necessary over this winter.

29. At the time EGNB was evaluating the 7-year Block 1 contract, EGNB graphed its current supply contracts, with the addition of the 7-year Block 1 contract against its forecast demand over the next 5 years. This analysis did not distinguish demand by product or rate class as EGNB contracts for supply to meet aggregate customer demand, resulting in the following graph:



As the chart clearly indicates, the 7-year Block 1 contract was expected to satisfy a portion of EGNB's daily gas needs during the contract term. It was not expected to satisfy all of EGNB's daily needs.

30.

a. EGNB had discussions over an extended period of time with Alton Gas Storage ("Alton") regarding their proposed storage project near Truro, Nova Scotia. These discussions and subsequent negotiations resulted in EGNB entering into a Precedent Agreement with Alton in May 2009 for capacity at the storage facility once it was constructed. Since that time, the Alton project has not progressed and at the end of June 2010 the Precedent Agreement expired.

   EGNB also evaluated the non-binding open season conducted by Corridor Resources in the spring of 2008 for a salt cavern storage project near Sussex, New Brunswick. Based on the proposed pricing of the storage, EGNB did not believe the storage would be an economic alternative for EGNB and as a result did not respond to the open season.

b. EGNB does not have any written analyses related to storage

c. Please see the response to 30(a) above.

d. Please see the response to 30(a) above. Since the contract is commercially sensitive, subject to confidentiality and no longer in effect, EGNB does not believe the contract is relevant to this proceeding and is therefore not provided.

e. EGNB believes that Alton issued a press release in June 2008 that indicated that EGNB and Alton were pursuing an agreement for EGNB to lease storage at the Alton facility. EGNB is unable to locate a copy of Alton's release. EGNB is also unable to locate any press articles related to this.

31. EGNB does not have experience in calculating the requested confidence interval. As a result, EGNB is unable to provide the requested interval.

32. As EGNB is unable to provide the confidence interval in 31. above, EGNB is unable to provide the requested information.

33. EGNB cannot provide a value-at-risk (VaR) analysis for December 2010 to December 2014 as it is not familiar with this type of analysis. EGNB's understanding of this analysis is that it would be to attach a value to a risk that EGNB would be unable to sell its contracted commodity in the future. Given that this proceeding is only reviewing information through 2011 and EGNB does not expect to see a dramatic change in its base of EUG customers during that period, EGNB does not believe such an analysis (based on its understanding) is relevant to this proceeding.

34. EGNB cannot comment on the financial risk to itself and its customers in this instance, as EGNB is unable to provide the VaR analysis in 33. above.

35. EGNB has not performed or reviewed any analyses of the effects of exploration and production in the Marcellus Shale on prices in the Northeast United States. Fundamentally, any increase in North American natural gas supply will act to suppress natural gas prices.

36. EGNB has not researched any new pipelines that may be planned to bring the Marcellus shale gas to load centres as EGNB does not believe it has a direct impact on EGNB's operations or gas supply activities. As a result, EGNB does not have the requested information.

37. EGNB cannot describe the projected effect of the developments cited in 35. and 36. above, as no analyses have been performed or reviewed by EGNB. Given the general industry discussion surrounding the Marcellus Shale development, EGNB believes the long term

effects of this project have already been reflected in current (NYMEX) futures market and forward North American basis curves.

38. EGNB is unclear as to what the "developments price cited in 35. and 36. above" refers to. EGNB does not expect the development of the Marcellus Shale project to have any effect on security of supply for EGNB's gas commodity customers as EGNB is not aware of any projects that are planned to move this gas into the New Brunswick market.

39. As stated in 38. above, EGNB is unclear as to what the "developments price cited in 35. and 36. above" refers to. Also, given that EGNB is not aware of any projects that would attach Marcellus Shale supply to the New Brunswick market, EGNB does not believe the project's development will have any effect on its commodity gas procurement strategy. EGNB will continue to explore the most economic options for New Brunswick customers with respect to its procurement policy. To the extent that the development of the Marcellus Shale does provide other supply opportunities for EGNB in the future, EGNB would purse them at that time.

Reference: EOS Fee Allocation.

Question:

1. With reference to Exhibit A, Page 8, Answer 14, please provide copies of emails, notes, or correspondence between EGNB and EOS manager or employees related to the adjustment to the allocation of the EOS fees.

Response:

1. EGNB is not able to provide copies of emails, notes or correspondence on this matter. As stated in Mr. Butler's report and in Exhibit A, page 8, the adjustment to the allocation of EOS fees was a result of an informal telephone conversation, whereby EGNB was discussing the impact of system improvements to EOS workload and overall time requirements to provide EGNB services.

Reference: Regulated Activities.

Question:

1. With reference to Exhibit A, Page 4, Answer 9, please provide documentation to support the statement that, with respect to EGNB, "all of its business activities are regulated." Are there any business activities, over which EGNB has control, that are not regulated?

Response:

1. All aspects of EGNB's operations are regulated in some manner. Distribution services, installation and service activities, including associated equipment protection plans, and agent, billing and collection services are all included in the utility revenue requirement reviewed and approved by the Board and EGNB's commodity sales are also subject to review by the Board.

Reference: John Butler Report on Purchase and Sale of Natural Gas.

Question:

1. Please provide an electronic copy of EGNB's workpapers showing the calculation of the standard offer prices for each month of 2009 in spreadsheet form, with formulas intact. These should correspond to the standard offer prices posted on the EGNB website.

2. Please provide an electronic copy of EGNB's workpapers showing the calculation of the PGVA in spreadsheet form, with formulas intact, on a monthly basis during 2009.

3. Please provide an electronic copy of EGNB's workpapers showing the calculation of the PGVA for Alternative Products in spreadsheet form, with formulas intact, on a monthly basis during 2009.

4. Please provide an electronic copy of the activity in the EUG and EGNBLP General Ledgers during 2009.

5. Please provide the report from EOS with timesheets justifying the charges to EUG, as described in the Butler report at p. 15.

6. With regard to the gas purchasing plan for 2009,

   a. Please provide a copy of the detailed gas purchasing plan that governed EGNB's purchases for 2009. (Note: Mr. Butler states on page 17 that the plan filed with the Board does not address 2009.)

   b. If EGNB did not have a plan for 2009, why did it not have one?

   c. Please specify the dates in 2009 on which EGNB entered into new gas supply contracts, as referred to by Mr. Butler on page 17 of the report ("it can be disclosed that new gas supply contracts signed by EGNBLP in 2009 and existing purchase and sales contracts were reviewed and discussed with EGNBLP personnel.")

   d. How can Mr. Butler deem EGNB to be in compliance with the regulations if as he states "although the gas purchases in 2009 could be reviewed they could not be tested for compliance with the UGPP as filed with the Board."?

7. Please provide copies of all email exchanges between Butler and Paul Hamilton and other EGNB employees related to this engagement

8. Please decompose the EUG price change for each month during 2009 into:

   a. Change related to movement in the average forward price for the next 12-months at Tetco-M3 and Transco Zone 6;

b. Change related to the implied basis to Dracut based on spot price developments;

c. Change related to FX forward price movements;

d. Change related to forecast pipeline transportation costs;

e. Change related to forecast EGNB administrative costs; and

f. Change related to EGNB PGVA.

Please express each component of the price change in $/GJ. Please provide all supporting calculations in spreadsheet format.

9. Please demonstrate why the EUG price did not move from June 2009 to July 2009 and then again during the period August 2009 and December 2009. Please refer to the movements citing each of the factors referred to in 16. above.

10. Please explain how EGNB attributes its commodity-related expenses to EUG *versus* Alternative Offers. Which expenses are directly assigned or which are allocated? Please provide a detailed description of all factors that are taken into account and how those factors are used to attribute expenses to EUG or Alternative Offers.

11. Please provide a copy of the full firewall policy cited in Appendix C as being located on "the company's shared drive at Q:\Regulatory Documents\EGNB Firewall Document."

12. Is there any information cited in the full firewall policy that is not mentioned in Mr. LeBlanc's March 15 correspondence (Appendix C of the Butler report)? If so, which information is cited in the full firewall policy but not mentioned in Mr. LeBlanc's March 15 correspondence?

13. With respect to Appendix C, when does EGNB learn the date on which a customer's contract with a non-EGNB gas supplier will end? What are EGNB's policies with regard to information required of competitive suppliers?

14. With reference to the following statement on page 23 of the Partnership financial statements: "As at December 31, 2009, the Partnership had transacted two fixed price forward physical commodity contracts to manage exposure to change in natural gas prices. The first contract covers the period of December 1, 2009 through October 31, 2010, to manage the price for one of its large natural gas customers with a contract value of $206. The second contract covers the period of November 1, 2009 to October 31, 2010 to manage the price for approximately 1,000 residential customers, with a contract value of $755."

    a. Are the contracts directly assigned to EGNB commodity offerings or does the gas purchase cost get aggregated and allocated to the different commodity offerings?

b. With respect to the second contract entered into on behalf of residential customers, please specify the date on which the forward physical was entered into, the fixed price agreed to for each month of delivery, and the delivery location.

c. Please provide a copy of all analyses performed by EGNB, an EGNB affiliate or a third-party contractor to assure that the transaction prices for these contracts were reasonable, prudent, and consistent with prevailing market conditions.

d. Please show how the quantity of gas procured under each fixed-price contract fulfills the needs of those customers on whose behalf the contracts were entered into. Please show for each day in 2009 the projected daily aggregate customer demand compared to the daily supply procured under the contracts.

Response:

1. EGNB is unable to provide the requested electronic copy of EGNB's workpapers showing the calculation of the standard offer prices as they contain confidential information. This information has been provided in electronic format to Mr. Butler, on behalf of the Board, and has been reviewed in this form by Mr. Butler.

2. EGNB does not have workpapers associated with the calculation of the PGVA. The PGVA balance arises from the general ledger entries associated with payments for gas supply related transactions and revenues from commodity sales.

3. Please see the response to 2. above. EGNB did not have a separate PGVA for its alternate products in 2009.

4. EGNB has one single general ledger for EGNBLP and there is no separate ledger for EUG. EGNB considers the general ledger activity for its gas purchase and sales activity to be confidential as many transactions identify specific suppliers. Also, this information was available for review by Mr. Butler. As a result, the requested information has not been provided.

5. Mr. Butler's report states on page 15, "…more detailed information would be needed, possibly a report from EOS with timesheets, to permit unqualified acceptance of the changes." This statement suggests a report from EOS may assist in the evaluation of the allocation of EOS fees, however it does not indicate that such a report exists. As indicated in EGNB's evidence, "EOS does not document the time spent performing each discrete activity" (Exhibit A, page 8). In other words, no report from EOS exists.

6.
   a. EGNB's purchasing practices for 2009 were governed by EGNB's original Gas Purchasing Plan, filed in 2003.

   b. As indicated in the response to a. above, the original Gas Purchasing Plan governed purchasing practices in 2009. The Board's November 13, 2009 decision required an updated Plan be filed with the Board prior to the next review.

c. EGNB entered into new gas supply contracts on July 22, 2009 and November 6, 2009.

d. EGNB believes that this question would need to be answered by Mr. Butler. EGNB cannot speak on his behalf. However, as mentioned in b. above, EGNB believes the previous Gas Purchasing Plan was applicable during 2009 and could have been used to assess EGNB's 2009 gas purchasing activities.

7. Copies of the requested email exchanges that EGNB does not consider to be confidential are attached. Some of the email exchanges contain specific information related to bid responses from commodity suppliers which EGNB considers to be confidential. These will be provided in confidence to the Board.

8. EGNB is unable to provide the requested decomposition of the EUG price for each month during 2009. EGNB's monthly calculation of EUG price is arrived at using the following steps:
   - the total expected cost of gas for the next 12 month period is calculated (in $CAD)
   - the last known balance of the PGVA is added (e.g. the November 2008 PGVA balance is used for the January 2009 calculation)
   - This total is divided by the expected customer demand for the next 12 month period (in GJ)

   While EGNB recognizes that all of the factors identified in the question contribute to a change in the EUG price, EGNB cannot isolate the magnitude by which each factor contributes to this change in $/GJ. Both the purchase volumes and EUG demand volumes change month to month on a rolling 12 month basis. This fluctuation in volume changes the overall weighting from one month to the next of each of the contributing factors identified in this question, making it virtually impossible to attribute an amount to a discrete factor with any degree of accuracy.

9. The EUG price did not move from June 2009 to July 2009 and then again during the period August 2009 to December 2009 as the aggregate impact of all of the factors that can impact the EUG price resulted in a price change that was less than the 3% threshold employed for making a change to the EUG price charged to customers.

10. EGNB attributes its commodity-related expenses to EUG and Alternate Offers on the basis of which offering caused the cost. ABC and contract renewal expenses are directly assigned based on the commodity offering being used by the customer. Hedge expenses are only related to Alternate Offers and as such are assigned directly to Alternate Offers. Volume related expenses such as commodity expenses and transportation expenses are assigned based on GJ consumption by EUG and Alternate Offers. Other administrative expenses are allocated based on estimated time spent by the Gas Supply Analyst on the different products. In 2009, the allocation of EOS fees was assigned on an arbitrary basis to EUG and Alternate Offers as the costs being allocated to either category were not considered material in comparison to the total costs and any revenue to cost variances would ultimately end up in

the PGVA. With the change in treatment for excess revenues from Alternate Offers in 2010, EOS fees are now being allocated on a volumetric basis.

11. A copy of EGNB's firewall policy is attached.

12. The full firewall policy, which is attached to the response to 11. above, is seven pages long. As a result there is information in the policy that is not contained in the two paragraph synopsis provided in Jamie Leblanc's March 15 correspondence that highlights the key elements of the firewall policy. Given that the firewall policy has been provided, EGNB will not reiterate it in this response.

13. EGNB, and for clarity this does not include the employees associated with EUG, learns the date on which a customer's contract with a non-EGNB gas supplier will end on at the time a Modification to Distribution Services Agreement and Collection Services Agreement is submitted to EGNB by the non-EGNB gas supplier. EGNB requires licensed gas marketers to provide information in accordance with the distribution service agreements with each marketer.

14.
   a. The costs for the contracts referred to in the quoted statement are directly assigned to Alternative Offers in aggregate. They are not allocated to different commodity offerings.

   b. The second contract referenced was entered into on August 20, 2009. EGNB is unable to provide the fixed price agreed to in the contract as this information is confidential.

   c. EGNB had discussions with its suppliers to test the price of this contract as reasonable, prudent or consistent with prevailing market conditions. EGNB also considers participation by 976 customers to be a valid indication of price reasonableness and consistency with prevailing market conditions.

   d. EGNB does not have this information available on a daily basis. However, the following table provides the information for each of these contracts by month during the relevant months of 2009.

Fixed Price Contract #1 - Single Large Customer

	Nov-09	Dec-09
Contracted Volume (GJ)	-	2,617
Consumption Volume (GJ)	-	1,770
Difference Long/(Short) (GJ)	-	846

Fixed Price Contract #2 - Residential Fixed Price Offer

	Nov-09	Dec-09
Contracted Volume (GJ)	5,381	11,447
Consumption Volume (GJ)	6,037	8,317
Difference Long/(Short) (GJ)	(657)	3,130

Reference: Partnership Financial Statements.

Question:

1. With reference to the following statement on Page 23 of the partnership financial statements: "As at December 31, 2009, the Partnership had transacted two fixed price forward physical commodity contracts to manage exposure to change in natural gas prices. The first contract covers the period of December 1, 2009 through October 31, 2010, to manage the price for one of its large natural gas customers with a contract value of $206. The second contract covers the period of November 1, 2009 to October 31, 2010 to manage the price for approximately 1,000 residential customers, with a contract value of $755."

   a. In which line item of the Commodity Sales Report is the cost of each physical hedge cited above included?

   b. Are the contracts directly assigned to EGNB commodity offerings or does the gas purchase cost get aggregated and allocated to the different commodity offerings?

   c. With respect to the second contract entered into on behalf of residential customers, please specify the date on which the forward physical was entered into, the fixed price agreed to for each month of delivery, and the delivery location.

   d. Please provide a copy of all analyses performed by EGNB to assure that the transaction prices for these contracts were reasonable, prudent, and consistent with prevailing market conditions.

2. Please show how the quantity of gas procured under each fixed-price contract fulfills the needs of those customers on whose behalf the contracts were entered into. Please show for each day in 2009 the projected daily aggregate customer demand compared to the daily supply procured under the contracts.

3. "On page 22, EGNB states Thc Partnership's customers taking EGNB's system gas ("EUG") are exposed to movements of the price of energy commodities. In order to manage these exposures for EUG customers, Enbridge Inc., on behalf of the Partnership, utilizes derivative financial instruments to create offsetting positions to specific exposures." With respect to this statement,

   a. Please clarify whether these derivative transactions are only entered into on behalf of EUG customers to manage customers' commodity gas price risk.

   b. Please clarify whether Enbridge Inc. also enters into derivative transactions hedges to protect against the risk of an unfavorable development in the spread between the market price of gas and oil-related products that would cause EGNB to lower its market-based distribution rates. Has Enbridge Inc. in the past ever entered into hedges on behalf of the partnership to protect against unfavorable commodity market developments that lower EGNB's market-based distribution rates? If so, please describe these hedges and note when they were entered into and for what time periods.

c. If Enbridge Inc. were to enter into derivative financial instruments on behalf of the EGNB Partnership, how would EGNB (and/or its customers as the case may be) receive the benefits of those derivative instruments?

d. Please clarify whether the derivative financial instruments to which EGNB refers (to the extent they are indeed used) would appear on both the financial statements of Enbridge Inc. and EGNB LP, or whether they would only appear on the financial statements of Enbridge Inc.

e. Please explain in detail how both EGNB LP and Enbridge Inc. would account for those instruments. Please address the accounting during the period leading up to settlement, as well as the accounting at the time of settlement. Please also explain the regulatory treatment of the EGNB LP accounting entries related to these derivatives.

f. Did Enbridge Inc. employ any derivative financial instruments on behalf of the EGNB partnership for 2009? Please interpret "for 2009" to include any derivative financial instruments whose settlement makes reference to a day, week, month, season or any time period during 2009, and without regard to the date on which the derivative instrument was entered into. If yes, please specify the terms and conditions of the derivative financial instruments entered into by Enbridge Inc. on behalf of the partnership. When describing the terms and conditions, please specify the type of derivative (*e.g.*, swap, option, future, forward), the time periods covered, the notional delivery location, the prices agreed to, and any relevant indices to which the derivatives refer. Please specify each line item in the EGNB partnership financial statements and regulatory financial statements where these derivatives costs or benefits appear?

4. The partnership financials state on page 23 that "The Partnership did not have any effective cash flow hedging instruments as at December 31, 2009." Please clarify whether the partnership had any effective or ineffective cash flow hedging instruments at any time during 2009. Please specify the terms and conditions of the hedge instruments and identify when they were held and for what purpose.

5. Please specify the nature of the commitment and contingency that has been redacted from section 14 f) of the Notes to the Partnership financials. Why does EGNB believe that this information cannot be disclosed to parties who sign a confidentiality undertaking? Please specify the harm that would be caused from disclosure and to whom such harm would ensue.

6. With respect to section 14 e) of the Notes to the Partnership financials:

   a. Is Louisbourg Pipelines an affiliated company? Please specify all owners of Louisbourg Pipelines.
   b. Has Louisbourg Pipelines agreed to fixed rates for labour under that agreement? If not, how do the labour rates change over time during the contract term?
   c. Has Louisbourg Pipelines agreed to fixed rates for materials under that agreement? If not, how do the rates for materials change over time during the contract term?

Response:

1.
   a. The cost of these hedges is included as part of the total Commodity Expenses on page 2 of the Commodity Sales Report.

   b. Please see EGNB's response to Public Intervenor Interrogatory No. 16(14(a)).

   c. Please see EGNB's response to Public Intervenor Interrogatory No. 16(14(b)).

   d. Please see EGNB's response to Public Intervenor Interrogatory No. 16(14(c)).

2. Please see EGNB's response to Public Intervenor Interrogatory No. 16(14(d)).

3.
   a. The referenced derivative transactions are only entered into on behalf of customers taking commodity service from EGNB to manage customers' commodity price risk. In the context of the Partnership statements, this encompasses both the Standard Offering and Alternate Products.

   b. Enbridge Inc. has not entered into derivative transactions on behalf of EGNB to protect against the risk of an unfavourable spread between the market price of gas and oil-related products at any time.

   c. EGNB cannot speculate on how such transactions would provide benefits to EGNB and/or its customers as no such transactions have been contemplated.

   d. The derivative instruments would only appear on the statements of EGNB LP.

   e. As the derivative instruments mentioned are only associated with the provision of EUG (Standard Offer and Alternate Products) all costs would be recorded to the accounts of EUG.

   f. The only derivative transactions used by EGNB LP in 2009 are the two transactions described in the text referenced in question 1. above. Please see EGNB's response to Public Intervenor Interrogatory No. 16(14) for additional information related to these transactions.

4. During 2009, the Partnership did not have any effective hedges, however it did have fixed price forward physical commodity contracts (hedges) which for accounting purposes were deemed ineffective. During 2009, EGNB had entered into gas contracts where they set out to secure locked in pricing for customers. Although these hedges did not meet the definition of effective hedges under hedge accounting rules, these hedges were effective in the sense that the difference between the fair value of the cash flows of the contracts (ie. purchase of the gas, and sale of the gas to the customers) was very insignificant and not deemed to be material in the eyes of the Partnership's auditors.

The following hedges were in place during 2009:

- October 1, 2008 through April, 2009 for approximately 263,000 MMBtu of natural gas
- November 1, 2008 to October 31, 2009 gas for approximately 1,165 residential customers
- November 1, 2008 through October 31, 2009 for approximately 35,857 MMBtu of natural gas
- December 1, 2009 through October 31, 2010 for approximately 26,800 MMBtu of natural gas
- November 1, 2009 to October 31, 2010 for approximately 1,040 residential customers

5. The information redacted relates to provisions in a contract between EGNB and a non-affiliated party that contains a specific confidentiality provision regarding the disclosure of the contract information to any party. Disclosure to any party other than the Board would thus require an order of the Board. In addition, EGNB does not believe that disclosure to participants, under any conditions, is necessary in the public interest given that the redacted portion of the audited statements does not detract from parties gaining a full understanding of the financial results of EGNBLP for 2009.

6.
   a. Louisbourg Pipelines is not affiliated with EGNB. EGNB entered into a contract with Louisbourg SBC limited partnership as represented by Louisbourg Simard-Beaudry Construction Inc. for the pipeline construction and maintenance activities it performs for EGNB. EGNB does not know who the partners are in Louisbourg SBC limited partnership.

   b. The current Louisbourg contract is a one year contract that has an expiry date of May 31, 2011 with a renewal provision that could extend it to May 31, 2012. Under the terms of the renewal provision, Louisbourg's labour and material rates would increase from the fixed 2010 rates by the change in the New Brunswick Consumers Price Index from March 2010 to March 2011.

   c. Please see the response to 6b. above.