Public Intervenor
Interrogatory No. 1

Reference: Historical Forecasts and Actuals

Interrogatory:

1. For each customer class and for each year of operation, please provide both forecast and actual number of customers and throughput.
2. Please provide the financial information equivalent to that in Schedule C for the prior ten year period with and without the amortisation of deferred development costs and other deferrals associated with EGNB's development status, that is, without the expenses that would not be incurred by a mature gas distribution company.
3. Is it correct to infer that apart from the amortisation of deferred development costs and the regulatory deferral all other items except for the revenues would be regard as legitimate items for a mature gas LDC?
4. For each year since 2000 please provide the regulated assets, clearly distinguishing between property plant and equipment and other assets that are normal for a mature utility and the deferred charges reflective of EGNB's development status.
5. For each year since 2000 please indicate the revenue requirement that would result if it had been possible to apply cost of service regulation in the normal way assuming the National Energy Board's formula ROE and a 36% common equity ratio and Enbridge Inc's borrowing cost, that is without the 1.0% premium. This should reflect the expenses in (1) and (3) above that do not include the deferrals and the rate base in iii without the deferred charges.
6. Given the information in 1 – 4 above, please graph and provide the revenue deficiency in each year as the difference between the cost of service rates based on the absence of deferred charges and deferrals both in $ and as a percentage of the actual revenues.
7. Would it be fair to say that the development period has effectively ended when the deficiency estimated in (5) is zero, such that rates then cover the actual cost of service that would exist for a mature gas LDC? If rates are set in excess of this level then if the excess goes towards reducing the deferred charges would EGNB accept that this indicates that the deferred charges are being reduced and EGNB is post development? If not, please explain in detail.
8. Further to (6) above is it acceptable to define post development in terms of earning a cost of service that includes: the amortisation of deferred charges, the ROE, interest cost and capital structure of a development period gas LDC and financial charges relative to a return on deferred charges. Please explain in detail.

Response:

1. The following tables provide the requested information (the forecast figures reflect the forecast prepared by EGNB preceding each year):

Actual number of cummulative customers:

	2001	2002	2003	2004	2005	2006	2007	2008	2009
SGS	69	775	1,756	2,427	3,398	4,584	-	-	-
SGSRE	-	-	-	-	-	-	1,319	1,703	2,009
SGSRO	-	-	-	-	-	-	4,454	4,759	4,989
SGSC	-	-	-	-	-	-	1,104	1,310	1,406
GS	67	287	455	547	666	820	1,056	1,365	1,521
CGS	20	67	80	145	179	208	228	250	246
LFO Tier I	4	11	14	17	18	18	20	22	24
LFO Tier II	-	-	-	-	1	1	2	2	2
LFO Tier III	-	-	-	-	1	1	2	2	2
HFO	1	6	7	7	7	7	7	7	9
	161	1,146	2,312	3,143	4,268	5,637	8,188	9,416	10,204

Actual annual throughput (TJs):

	2001	2002	2003	2004	2005	2006	2007	2008	2009
SGS	2	37	130	222	310	360	-	-	-
SGSRE	-	-	-	-	-	-	125	154	180
SGSRO	-	-	-	-	-	-	272	337	359
SGSC	-	-	-	-	-	-	189	229	254
GS	11	135	331	443	513	568	772	893	1,063
CGS	12	165	330	437	668	732	940	981	1,014
LFO Tier I	19	228	362	548	1,094	1,095	1,218	1,524	1,367
LFO Tier II	-	-	-	-	-	-	-	-	-
LFO Tier III	-	-	-	-	-	-	-	-	-
HFO	173	548	608	654	810	819	953	924	974
	216	1,113	1,760	2,303	3,396	3,573	4,469	5,042	5,211

Forecast number of customers:

	2001	2002	2003	2004	2005	2006	2007	2008	2009
SGS	69	3,209	3,135	4,852	3,704	5,059	-	-	-
SGSRE	-	-	-	-	-	-	2,109	2,321	2,536
SGSRO	-	-	-	-	-	-	4,045	5,374	5,114
SGSC	-	-	-	-	-	-	1,132	1,786	1,773
GS	67	205	503	772	734	876	1,220	1,490	1,648
CGS	20	118	155	131	207	214	297	282	278
LFO Tier I	4	11	19	15	19	21	21	21	22
LFO Tier II	-	-	-	1	1	1	2	2	2
LFO Tier III	-	-	-	1	1	1	2	2	2
HFO	1	2	8	11	8	7	7	7	7
	161	3,545	3,820	5,781	4,672	6,177	8,831	11,281	11,378

Forecast annual throughput (TJs):

	2001	2002	2003	2004	2005	2006	2007	2008	2009
SGS	35	105	151	363	247	342	-	-	-
SGSRE	-	-	-	-	-	-	224	200	216
SGSRO	-	-	-	-	-	-	206	417	367
SGSC	16	15	90	124	129	170	195	311	354
GS	116	203	798	841	665	749	855	1,141	1,218
CGS	721	420	608	834	782	938	1,111	1,164	1,173
LFO Tier I	312	206	904	881	982	1,055	854	1,522	1,909
LFO Tier II					256	300	522	531	291
LFO Tier III					146	71	100	100	3
HFO	94	324	763	760	961	803	778	957	906
	1,293	1,272	3,316	3,803	4,168	4,429	4,845	6,343	6,437

2. Please see the attached financial information for 2000 – 2009. These reflect the financial results as filed with the Board. EGNB is unable to provide statements for the same periods without the amortization of deferred development costs and other deferrals associated with EGNB's development period as requested, as EGNB is unable to assess which expenses may or may not have been incurred had EGNB been a mature utility. As well, EGNB is unable to determine what expenses may, or may not, have been permitted for regulatory purposes by the Board.

3. EGNB does not believe it is correct to infer that the amortization of deferred development costs and the regulatory deferral would not be regarded as "legitimate" items for a mature utility. Mature utilities often maintain deferral accounts. Also, EGNB does not believe it is correct to infer that amounts recovered through the deferred development costs would not be regarded as "legitimate" for a mature utility as many of the expenses that are currently considered development costs are also incurred by mature utilities. For example, most mature utilities would have marketing expenses. That being said, EGNB's regulatory deferral and the amortization of deferred development costs have been approved by the Board to reflect the greenfield nature of EGNB's distribution business. All other items would also be regarded as legitimate items for a mature gas LDC.

4. Please see the response to 2. above.

5. EGNB is unable to determine which assets may or may not be included as legitimate costs incurred and recovered through rates by a mature utility. As a result, EGNB is unable to provide the requested revenue requirement calculation. Even if possible, EGNB does not believe it is relevant to respond to the historic hypothetical being requested

6. As EGNB is unable to determine what the revenue requirement may have been in the absence of deferred charges and deferrals, it is unable to provide the requested information.

7. As EGNB is unable to respond to 5. above, and in any event believes it is an irrelevant hypothetical request, EGNB cannot specifically respond. As a general comment, EGNB does not believe this is a fair statement. EGNB believes that the criteria identified by the Board in its December 1, 2009 Decision arising from the Development Period Criteria proceeding, subject to any adjustments arising from EGNB's May 13, 2010 variance request, will be the basis for determining if the Development Period has ended.

8. As EGNB is unable to respond to 6. above, EGNB cannot specifically respond. As a general comment, EGNB does not believe this is an acceptable means of defining post development as it fails to include a number of items typically included in the revenue requirement, such as operating and maintenance expenses, bad debts, property taxes and income taxes. The exclusion of any element that forms part of the revenue requirement would fail to provide EGNB with the opportunity to earn a fair return.

Public Intervenor
Interrogatory No. 2

Reference: Exhibit C, Schedule 1

Interrogatory:

1. Please provide Exhibit C, Schedule 1 in MS Excel electronic format, with formulae intact, including supporting workpapers.

Response:

1. Exhibit C, Schedule 1 is attached in MS Excel electronic 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 long term forecasts. While requests regarding the basis for arriving at specific aspects of the 10 year forecast are relevant, EGNB does not believe providing this entire collection of information is relevant to this proceeding.

Public Intervenor
Interrogatory No. 3

Reference: Exhibit C, Schedule 1, Note 9, Gas Distribution Rates

Interrogatory:

1. In MS Excel electronic format, for 2010 to 2015, please provide the supporting workpapers for each gas distribution per-GJ rate forecast, including but not necessarily limited to the forecasts for:

   i) Typical customer alternative fuel and gas consumption level;

   ii) Price of alternative fuel, including fuel price, transportation costs and/or location differentials, efficiency factors, and exchange rates;

   iii) Commodity cost of natural gas (EUG, EVP);

   iv) Assumed savings rate for delivered natural gas service.

   Please provide the basis for each forecast. For the natural gas price forecast, please be explicit with respect to the gas supply sources assumed and the prices for each.

Response

1. The following tables, which have also been provided in MS Excel electronic format, provide the derivation of the distribution rate per GJ forecast for 2011 to 2015. No information has been provided for 2010, as Board approved rates were used and no derivation was required.

Wholesale Market Data					
Forecast:	**2011**	**2012**	**2013**	**2014**	**2015**
Nymex (US$/mmbtu)	$5.46	$5.91	$6.18	$6.44	$6.73
No.2 Heating (US$/bbl)	$2.24	$2.34	$2.42	$2.46	$2.51
Fx (CAD/US)	1.0482	1.0508	1.0508	1.0508	1.0508
EUG ($/GJ)	7.75	8.12	8.37	8.41	8.78
Retail NG prices					
SGS	7.75	8.12	8.37	8.41	8.78
GS	7.75	8.12	8.37	8.41	8.78
CGS	7.75	8.12	8.37	8.41	8.78
LFO (Comm Var)	7.66	8.13	8.39	8.66	8.95
21 Day Avg - Yearly 2010 Data (June 3, 2010)					
Natural Gas (Henry Hub)	$5.46	$5.91	$6.18	$6.44	$6.73
Nymex No.2 Heating Oil	$2.24	$2.34	$2.42	$2.46	$2.51
WTI Crude Oil	$82.08	$84.19	$85.67	$87.06	$88.65

RETAIL OIL Calculations

	2011	2012	2013	2014	2015
No.2 Heating Oil (US$/Litre)	2.2397	2.3393	2.4242	2.4636	2.5085
Exchange rate (CAN$/US$)	1.0482	1.0508	1.0508	1.0508	1.0508
No.2 Heating Oil (CAN$/Litre)	0.6202	0.6494	0.6730	0.6839	0.6964
Market Spreads (Can$/litre)					
SGSRO	0.2250	0.2250	0.2250	0.2250	0.2250
SGSC	0.2050	0.2050	0.2050	0.2050	0.2050
GS	0.1950	0.1950	0.1950	0.1950	0.1950
CGS	0.1850	0.1850	0.1850	0.1850	0.1850
LFO	0.1750	0.1750	0.1750	0.1750	0.1750
Monthly Retail Oil Price (Can$/litre)					
SGSRO	0.8452	0.8744	0.8980	0.9089	0.9214
SGSC	0.8252	0.8544	0.8780	0.8889	0.9014
GS	0.8152	0.8444	0.8680	0.8789	0.8914
CGS	0.8052	0.8344	0.8580	0.8689	0.8814
LFO	0.7952	0.8244	0.8480	0.8589	0.8714
HFO Retail Oil Price (WTI)					
Average	$82.08	$84.19	$85.67	$87.06	$88.65
72.00% US$/bbl	59.0990	60.6146	61.6818	62.6829	63.8251
HFO $Can/bbl	61.9447	63.6956	64.8171	65.8691	67.0693
HFO $Can/Litre	0.3896	0.4006	0.4077	0.4143	0.4219

SGSRE - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Lines 1 - 5 not used**							
6	**Total Alternative Energy Cost**	$/ year	Retail Electricity Cost	$2,642.14	$2,721.40	$2,803.04	$2,887.14	$2,973.75
7	**Target Savings Level**	%	Assigned	20%	20%	20%	20%	20%
8	**Target Savings Amount**	$	Line 6 x Line 7	$528.43	$544.28	$560.61	$577.43	$594.75
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$2,113.71	$2,177.12	$2,242.43	$2,309.71	$2,379.00
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	111	111	111	111	111
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	19.0424	19.6137	20.2021	20.8082	21.4324
12	**Commodity Cost**	$/GJ	EUG Price	7.7467	8.1165	8.3661	8.4099	8.7786
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	11.2957	11.4972	11.8360	12.3983	12.6538
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$1,253.82	$1,276.19	$1,313.80	$1,376.21	$1,404.57
15	**Monthly Customer Charge**	$	Assigned	$16.00	$16.00	$16.00	$16.00	$16.00
16	**Annual Customer Charge**	$	Line 15 * 12	$192.00	$192.00	$192.00	$192.00	$192.00
17	**Average Contract Demand**	GJs	Average					
18	**Contract Demand Charge**	$	Assigned	0	0	0	0	0
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	0	0	0	0	0
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$1,061.82	$1,084.19	$1,121.80	$1,184.21	$1,212.57
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$9.5660	$9.7675	$10.1063	$10.6685	$10.9241

SGSRO - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.8452	$0.8744	$0.8980	$0.9089	$0.9214
2	**Assumed Efficiency factor**		Assigned	78.16%	78.16%	78.16%	78.16%	78.16%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	107	107	107	107	107
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	25.8532	25.8532
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	2,766.29	2,766.29	2,766.29	2,766.29	2,766.29
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$2,337.97	$2,418.86	$2,484.05	$2,514.27	$2,548.74
7	**Target Savings Level**	%	Assigned	20%	20%	20%	20%	20%
8	**Target Savings Amount**	$	Line 6 x Line 7	$467.59	$483.77	$496.81	$502.85	$509.75
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$1,870.38	$1,935.09	$1,987.24	$2,011.42	$2,038.99
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	84	84	84	84	84
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$22.2664	$23.0368	$23.6576	$23.9455	$24.2737
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.7467	$8.1165	$8.3661	$8.4099	$8.7786
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$14.5197	$14.9203	$15.2915	$15.5356	$15.4951
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$1,219.65	$1,253.31	$1,284.49	$1,304.99	$1,301.59
15	**Monthly Customer Charge**	$	Assigned	$16.00	$16.00	$16.00	$16.00	$16.00
16	**Annual Customer Charge**	$	Line 15 * 12	$192.00	$192.00	$192.00	$192.00	$192.00
17	**Average Contract Demand**	GJs	Average					
18	**Contract Demand Charge**	$	Assigned	0	0	0	0	0
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	0	0	0	0	0
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$1,027.65	$1,061.31	$1,092.49	$1,112.99	$1,109.59
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$12.2340	$12.6346	$13.0058	$13.2499	$13.2094

SGSC - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.8252	$0.8544	$0.8780	$0.8889	$0.9014
2	**Assumed Efficiency factor**		Assigned	78.16%	78.16%	78.16%	78.16%	78.16%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	285	285	285	285	285
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	25.8532	25.8532
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	7,368.16	7,368.16	7,368.16	7,368.16	7,368.16
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$6,079.95	$6,295.39	$6,469.04	$6,549.52	$6,641.33
7	**Target Savings Level**	%	Assigned	20%	20%	20%	20%	20%
8	**Target Savings Amount**	$	Line 6 x Line 7	$1,215.99	$1,259.08	$1,293.81	$1,309.90	$1,328.27
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$4,863.96	$5,036.31	$5,175.23	$5,239.62	$5,313.06
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	223	223	223	223	223
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$21.8115	$22.5843	$23.2073	$23.4961	$23.8254
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.7467	$8.1165	$8.3661	$8.4099	$8.7786
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$14.0648	$14.4678	$14.8412	$15.0862	$15.0468
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$3,136.45	$3,226.33	$3,309.59	$3,364.22	$3,355.44
15	**Monthly Customer Charge**	$	Assigned	$16.00	$16.00	$16.00	$16.00	$16.00
16	**Annual Customer Charge**	$	Line 15 * 12	$192.00	$192.00	$192.00	$192.00	$192.00
17	**Average Contract Demand**	GJs	Average					
18	**Contract Demand Charge**	$	Assigned	0	0	0	0	0
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	0	0	0	0	0
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$2,944.45	$3,034.33	$3,117.59	$3,172.22	$3,163.44
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$13.2038	$13.6069	$13.9802	$14.2252	$14.1858

GS - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.8152	$0.8444	$0.8680	$0.8789	$0.8914
2	**Assumed Efficiency factor**		Assigned	81.25%	81.25%	81.25%	81.25%	81.25%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	1,124	1,124	1,124	1,124	1,124
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	25.8532	25.8532
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	29,059.00	29,059.00	29,059.00	29,059.00	29,059.00
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$23,687.90	$24,537.56	$25,222.39	$25,539.80	$25,901.90
7	**Target Savings Level**	%	Assigned	15%	15%	15%	15%	15%
8	**Target Savings Amount**	$	Line 6 x Line 7	$3,553.19	$3,680.63	$3,783.36	$3,830.97	$3,885.29
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$20,134.71	$20,856.93	$21,439.03	$21,708.83	$22,016.61
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	913	913	913	913	913
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$22.0534	$22.8444	$23.4820	$23.7775	$24.1146
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.7467	$8.1165	$8.3661	$8.4099	$8.7786
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$14.3067	$14.7279	$15.1159	$15.3676	$15.3360
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$13,062.02	$13,446.61	$13,800.84	$14,030.60	$14,001.77
15	**Monthly Customer Charge**	$	Assigned	$16.00	$16.00	$16.00	$16.00	$16.00
16	**Annual Customer Charge**	$	Line 15 * 12	$192.00	$192.00	$192.00	$192.00	$192.00
17	**Average Contract Demand**	GJs	Average					
18	**Contract Demand Charge**	$	Assigned	0	0	0	0	0
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	0	0	0	0	0
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$12,870.02	$13,254.61	$13,608.84	$13,838.60	$13,809.77
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$14.0964	$14.5177	$14.9056	$15.1573	$15.1257

CGS - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.8052	$0.8344	$0.8580	$0.8689	$0.8814
2	**Assumed Efficiency factor**		Assigned	81.25%	81.25%	81.25%	81.25%	81.25%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	6,087	6,087	6,087	6,087	6,087
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	25.8532	25.8532
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	157,368.43	157,368.43	157,368.43	157,368.43	157,368.43
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$126,707.67	$131,308.96	$135,017.67	$136,736.59	$138,697.54
7	**Target Savings Level**	%	Assigned	15%	15%	15%	15%	15%
8	**Target Savings Amount**	$	Line 6 x Line 7	$19,006.15	$19,696.34	$20,252.65	$20,510.49	$20,804.63
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$107,701.52	$111,612.62	$114,765.02	$116,226.10	$117,892.91
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	4,946	4,946	4,946	4,946	4,946
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$21.7755	$22.5662	$23.2036	$23.4990	$23.8360
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.7467	$8.1165	$8.3661	$8.4099	$8.7786
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$14.0288	$14.4497	$14.8375	$15.0891	$15.0574
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$69,386.45	$71,468.44	$73,386.43	$74,630.56	$74,473.94
15	**Monthly Customer Charge**	$	Assigned					
16	**Annual Customer Charge**	$	Line 15 * 12	0	0	0	0	0
17	**Average Contract Demand**	GJs	Average	46	46	46	46	46
18	**Contract Demand Charge**	$	Assigned	$5.20	$5.20	$5.20	$5.20	$5.20
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	$2,870.40	$2,870.40	$2,870.40	$2,870.40	$2,870.40
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$66,516.05	$68,598.04	$70,516.03	$71,760.16	$71,603.54
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$13.4485	$13.8694	$14.2572	$14.5087	$14.4771

LFO - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.7952	$0.8244	$0.8480	$0.8589	$0.8714
2	**Assumed Efficiency factor**		Assigned	100%	100%	100%	100%	100%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	33,474	33,474	33,474	33,474	33,474
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	25.8532	25.8532
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	865,410.02	865,410.02	865,410.02	865,410.02	865,410.02
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$688,144.43	$713,448.10	$733,843.29	$743,296.03	$754,079.82
7	**Target Savings Level**	%	Assigned	10%	10%	10%	10%	10%
8	**Target Savings Amount**	$	Line 6 x Line 7	$68,814.44	$71,344.81	$73,384.33	$74,329.60	$75,407.98
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$619,329.99	$642,103.29	$660,458.96	$668,966.43	$678,671.84
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	33,474	33,474	33,474	33,474	33,474
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$18.5018	$19.1822	$19.7305	$19.9847	$20.2746
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.6615	$8.1284	$8.3946	$8.6575	$8.9477
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$10.8403	$11.0538	$11.3359	$11.3272	$11.3269
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$362,868.59	$370,013.46	$379,459.15	$379,167.69	$379,157.98
15	**Monthly Customer Charge**	$	Assigned					
16	**Annual Customer Charge**	$	Line 15 * 12	0	0	0	0	0
17	**Average Contract Demand**	GJs	Average	275	275	275	275	275
18	**Contract Demand Charge**	$	Assigned	$5.20	$5.20	$5.20	$5.20	$5.20
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	$17,160.00	$17,160.00	$17,160.00	$17,160.00	$17,160.00
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$345,708.59	$352,853.46	$362,299.15	$362,007.69	$361,997.98
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$10.3277	$10.5411	$10.8233	$10.8146	$10.8143

Note: Table shows the 2011 rate derived based on market data. This rate was not used in the forecast as the Board approved rate from 2010 Rate proceeding was assumed.

HFO - Derivation of Distribution Rates

		Units	Calculation	2011	2012	2013	2014	2015
1	**Alternative Energy Price**	CAN$/l	Retail Oil Price	$0.3896	$0.4006	$0.4077	$0.4143	$0.4219
2	**Assumed Efficiency factor**		Assigned	100%	100%	100%	100%	100%
3	**Typical Annual Oil Consumption**	GJs/year	Line 10 / Line 2	132,327	132,327	132,327	132,327	132,327
4	**Conversion Factor**	l/GJ	Assigned	25.8532	25.8532	25.8532	23.9636	23.9636
5	**Typical Annual Consumption**	in litres	Line 3 x Line 4	3,421,076.40	3,421,076.40	3,421,076.40	3,171,031.30	3,171,031.30
6	**Total Alternative Energy Cost**	$/ year	Line 1 x Line 5	$1,332,851.37	$1,370,483.21	$1,394,772.85	$1,313,758.27	$1,337,858.11
7	**Target Savings Level**	%	Assigned	5%	5%	5%	5%	5%
8	**Target Savings Amount**	$	Line 6 x Line 7	$66,642.57	$68,524.16	$69,738.64	$65,687.91	$66,892.91
9	**Target Natural Gas Cost**	$	Line 6 - Line 8	$1,266,208.80	$1,301,959.05	$1,325,034.21	$1,248,070.36	$1,270,965.20
10	**Typical Annual Natural Gas Consumption**	GJs/ year	Typical Customer	132,327	132,327	132,327	132,327	132,327
11	**Target Burner Tip Price**	$/GJ	Line 9 / 10	$9.5688	$9.8390	$10.0133	$9.4317	$9.6047
12	**Commodity Cost**	$/GJ	EUG or EVP price	$7.6615	$8.1284	$8.3946	$8.6575	$8.9477
13	**Target Distribution Rate**	$/GJ	Line 11 - Line 13	$1.9073	$1.7106	$1.6187	$0.7742	$0.6570
14	**Target Annual Distribution Charge**	$	Line 13 x Line 10	$252,388.82	$226,352.88	$214,202.58	$102,451.50	$86,944.08
15	**Monthly Customer Charge**	$	Assigned					
16	**Annual Customer Charge**	$	Line 15 * 12					
17	**Average Contract Demand**	GJs	Average	865	865	865	865	865
18	**Contract Demand Charge**	$	Assigned	$3.90	$3.90	$3.90	$3.90	$3.90
19	**Revenue from Demand Charge**	$	Line 17 * Line 18 * 12	3373.5	$40,482.00	$40,482.00	$40,482.00	$40,482.00
20	**Target Revenue From Delivery Charge**	$	Line 14 - Lines 16 or 19	$249,015.32	$185,870.88	$173,720.58	$61,969.50	$46,462.08
21	**Distribution Delivery Charge**	$/GJ	Line 20/Line 10	$1.8818	$1.4046	$1.3128	$0.4683	$0.3511

Public Intervenor
Interrogatory No. 4

Reference: Exhibit C, Schedule 1, Note 9, Cumulative Customers

Interrogatory:

1. Regarding the 2,545 forecast new small general electric customers between 2010 and 2019, to the extent available, please estimate the number of new customers who convert from baseboard electric, the number of new construction, and the number of other customers (please specify).

2. Of the existing 2,353 small general electric customers, please estimate the number who converted from baseboard electric.

3. Please provide the basis for the forecast increase in number of customers for each rate class. To the extent available, please identify the geographical markets in which new customers are attached, and EGNB's assumed market penetration for on-main or near-main customers.

4. Please provide the forecast for incentive costs for each customer class, on a total and per-new-customer basis.

5. Please provide the forecast for incremental service line costs for each customer class, on a total and per-new-customer basis.

6. Please provide the forecast for incremental meters/regulators costs for each customer class, on a total and per-new-customer basis.

Response:

1. EGNB has forecast 3,545 new small general service residential electric (SGSRE) customers between 2010 and 2019, not 2,545 as suggested in the question. The following table summarizes the expected source of these new customers:

Convert from baseboard electric	541
New construction	2,391
Convert from Electric central heat	613
	3,545

2. EGNB does not currently have 2,353 SGSRE customers. That is the total number of SGSRE customers that EGNB expects to have at the end of 2010. As of May 31, 2010, EGNB had 2,091 SGSRE customers. While EGNB does not have precise information regarding the previous electric heat source for SGSRE customers that converted from electricity, EGNB estimates that less than 100 customers would have converted from baseboard electric.

3. EGNB's forecast for the increase in the number of customers for each rate class is based on a review of more recent historical customer attachments in each rate class, excluding the impact of strategic projects, such as the conversion of private married quarters at Base Gagetown. Other factors such as remaining on or near main opportuntiies and the anticipated impact of new initiatives, such as programs to address electric baseboard conversions, were also taken into consideration.

   EGNB only forecasts its customer additions in aggregate and does not look at it on a geographical basis. Similarly, no assumptions were made regarding achieved penetration rates, outside of considering the impact of fewer on-main or near-main customers as growth continues.

4. The following tables provide the requested information:

	Cost per-new-customer
Residential	
- Retrofit	$ 3,000
- Electric Baseboard	$ 7,000
- New Construction	$ 3,500
SGSC	$ 10,000
GS	$ 15,500
CGS	$ 63,000

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	2,461,500	2,460,500	2,597,000	2,618,000	2,558,500	2,422,000	782,000	737,000	699,000	667,000
SGSC	1,125,000	1,117,500	1,230,000	1,065,000	915,000	802,500	-	-	-	-
GS	1,861,860	1,801,410	1,982,760	1,716,780	1,474,980	1,293,630	-	-	-	-
CGS	960,207	790,759	819,000	734,276	649,552	593,069	-	-	-	-
General Commercial	-	-	-	-	-	-	256,568	242,760	231,105	223,388
	6,408,567	6,170,169	6,628,760	6,134,056	5,598,032	5,111,199	1,038,568	979,760	930,105	890,388

5. The following tables provide the requested information:

Average Cost Per-New-Customer

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	$ 1,626	1,665	1,700	1,734	1,769	1,804	1,841	1,877	1,915	1,953
SGSC	$ 2,493	2,553	2,607	2,659	2,712	2,766	2,822	2,878	2,936	2,994
GS	$ 3,563	3,649	3,725	3,800	3,876	3,953	4,032	4,113	4,195	4,279
CGS	$ 7,093	7,264	7,416	7,565	7,716	7,870	8,028	8,188	8,352	8,519

Total Cost

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	$ 1,384,745	1,514,954	1,631,177	1,673,490	1,658,309	1,598,934	1,675,310	1,626,750	1,591,195	1,556,305
SGSC	$ 474,704	417,719	465,478	411,250	360,212	321,140	364,458	334,578	299,440	282,664
GS	$ 712,651	777,627	884,134	784,677	690,847	624,527	710,792	652,127	587,171	557,550
CGS	$ 309,275	236,015	258,954	239,088	218,323	215,010	245,659	189,801	186,437	182,862
	$ 2,881,376	2,946,315	3,239,743	3,108,506	2,927,692	2,759,610	2,996,218	2,803,256	2,664,243	2,579,381

6. The following tables provide the requested information:

Average Cost Per-New-Customer

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	$	178	182	186	190	194	197	201	205	210	214
SGSC	$	1,238	1,268	1,294	1,320	1,347	1,373	1,401	1,429	1,458	1,487
GS	$	1,867	1,912	1,952	1,991	2,031	2,072	2,113	2,155	2,199	2,243
CGS	$	2,565	2,627	2,682	2,735	2,790	2,846	2,903	2,961	3,020	3,081

Total Cost

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Residential	$	119,776	119,735	128,762	132,096	130,866	126,178	133,535	129,426	126,357	123,541
SGSC	$	185,691	188,880	212,261	187,462	164,280	146,964	166,714	152,901	137,011	129,344
GS	$	287,567	284,908	320,176	282,770	247,802	221,681	251,473	230,637	206,668	195,103
CGS	$	87,214	73,547	77,773	71,122	64,174	59,765	66,767	53,297	51,343	49,289
	$	680,248	667,070	738,971	673,450	607,122	554,588	618,489	566,261	521,379	497,277

Public Intervenor
Interrogatory No. 5

Reference: Exhibit C, Schedule 1, Note 9, and Schedule 2, Page 4

Interrogatory:

1. In MS Excel electronic format, please provide actual "cumulative customers" and "throughput" for each year from 2000 to 2009.
2. Please provide the basis for the standard profile for customer additions shown in Schedule 2.
3. Please explain why the consumption level of customer additions appears to be considerably greater than the average current customer usage in the SGSRE and SGSRO classes, and modestly greater for the GS class. For example, assuming that the reported customer counts are year-end values, the average SGSRO customer use in 2011 appears to be approximately 411,052/((5,253+5,521)/2) = 76.3 GJ. The forecast addition appears to assume 114 GJ per customer.
4. Please provide the detail for the timing of customer additions, showing when customers are added and the incremental usage for each year associated with customer additions.

Response:

1. The electronic file supporting the response to Public Intervenor Interrogatory No. 1(1) is attached.

2. The standard profiles that have been used in the forecast reflect the profiles used historically by EGNB. While the standard profile has been updated for rate setting purposes, these profiles have not yet been carried forward into EGNB's forecasting model as the impact of forecasting adds on this basis does not have a material impact over the typical planning horizon (e.g. 5 years), as noted in 3. below. EGNB is currently assessing the appropriate standard profiles to use for new attachments so that they can be integrated into its 2011 forecast.

3. The average consumption for the current customer base is not necessarily indicative of the throughput expected from new customers. For example, in the SGSRO class there are approximately 1,600 private married quarters which are located at CFB Gagetown. These customers tend to be small loads and not indicative of the types of loads that EGNB usually is seeking. Similar exceptions can occur in other rate classes.

   EGNB has assessed the impact on the throughput forecast if the historic averages were used for new customer additions. By applying these averages, EGNB estimates the annual throughput in Exhibit C, Schedule 1, Note 9 would be reduced by percentages ranging from 0.5% for 2010 to 3.6% in 2019.

4. The following tables provided the timing of customer additions in 2010 and 2011 and their associated incremental usage:

2010 Additions

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
SGSRE	23	4	65	52	14	4	7	13	28	56	53	37	**356**
SGSRO	14	2	4	4	12	18	22	29	46	36	32	34	**253**
SGSC	6	1	7	5	8	10	6	5	12	24	24	12	**120**
GS	5	5	10	4	11	6	10	12	23	23	15	15	**139**
CGS	2	2	2	-	14	5	2	-	1	2	-	-	**30**
LFO			1	1	-	-	-	-	-	-	-	-	**2**
HFO			-	-	-	-	-	-	-	-	-	-	**-**
OPS			-	-	-	-	-	-	-	-	-	-	**-**
CLVOPS			-	-	-	-	-	-	-	-	-	-	**-**
	50	**14**	**89**	**66**	**59**	**43**	**47**	**59**	**110**	**141**	**124**	**98**	**900**

2011 Additions

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
SGSRE	7	15	9	9	9	20	31	37	58	68	63	63	**389**
SGSRO	21	7	3	4	11	18	22	30	47	37	33	35	**268**
SGSC	11	9	8	4	6	10	9	11	18	27	22	14	**149**
GS	14	11	8	3	9	8	9	12	19	27	14	15	**149**
CGS	2	2	-	-	4	3	-	2	8	3	2	2	**28**
LFO	-	-	-	-	-	-	-	-	-	-	-	-	**-**
HFO	-	-	-	-	-	-	-	-	-	-	-	-	**-**
OPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
CLVOPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
	55	**44**	**28**	**20**	**39**	**59**	**71**	**92**	**150**	**162**	**134**	**129**	**983**

2010 Incremental Throughput (GJs)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
SGSRE	103	235	882	1,203	1,017	454	474	487	588	1,709	2,999	5,085	**15,235**
SGSRO	76	176	414	328	237	168	196	247	331	884	1,890	3,223	**8,170**
SGSC	43	202	982	776	456	177	191	211	299	1,005	2,008	3,670	**10,019**
GS	67	288	3,418	3,158	2,028	948	1,066	1,337	1,975	6,158	11,314	18,605	**50,362**
CGS	113	3,492	3,390	3,475	2,966	2,406	3,799	4,363	4,866	10,622	15,104	21,508	**76,103**
LFO	-	-	849	6,575	17,073	17,109	18,719	18,719	18,115	18,719	18,115	18,719	**152,712**
HFO	-	-	-	-	-	-	-	-	-	-	-	-	**-**
OPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
CLVOPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
	401	**4,393**	**9,937**	**15,515**	**23,778**	**21,261**	**24,445**	**25,364**	**26,173**	**39,096**	**51,429**	**70,810**	**312,602**

2011 Incremental Throughput (GJs)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
SGSRE	7,859	6,982	6,580	4,625	3,068	1,557	1,053	1,110	1,265	3,174	6,105	9,890	**53,267**
SGSRO	5,407	5,156	4,934	3,365	2,373	1,390	807	859	944	2,116	4,362	6,946	**38,659**
SGSC	5,905	5,666	5,152	3,035	1,856	929	702	738	844	1,865	4,042	7,118	**37,851**
GS	29,307	25,806	25,150	15,953	12,637	5,461	5,639	5,891	6,456	13,253	22,562	35,021	**203,137**
CGS	25,461	22,799	21,614	15,774	10,426	5,128	5,409	5,577	6,215	13,900	21,406	32,319	**186,030**
LFO	18,719	17,511	18,719	18,115	18,719	18,115	18,719	18,719	18,115	18,719	18,115	18,719	**221,004**
HFO	-	-	-	-	-	-	-	-	-	-	-	-	**-**
OPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
CLVOPS	-	-	-	-	-	-	-	-	-	-	-	-	**-**
	100,517	**90,903**	**88,728**	**65,493**	**52,147**	**34,136**	**33,382**	**34,003**	**35,104**	**56,202**	**82,698**	**119,901**	**793,215**

For the years 2012 – 2019, to recognize that customers will be added to the system throughout the year, EGNB assumes that on average only 45% of the annual throughput expected from a customer will be achieved in the year they are attached, as forecasts are not prepared on a monthly basis for these years. This results in the following incremental throughput:

Incremental Throughput (GJs)

	2012	2013	2014	2015	2016	2017	2018	2019
SGSRE	108,427	154,147	199,409	242,655	286,609	331,954	375,279	416,911
SGSRO	75,463	107,623	139,503	170,323	199,410	226,964	253,127	278,047
SGSC	73,200	103,250	129,185	151,659	173,577	195,729	215,453	233,169
GS	359,277	497,967	617,667	721,392	822,552	924,792	1,015,827	1,097,592
CGS	293,725	384,970	466,315	539,245	611,515	679,990	737,905	792,520
LFO	221,004	221,004	221,004	221,004	221,004	221,004	221,004	221,004
HFO	-	-	-	-	-	-	-	-
OPS	-	-	-	-	-	-	-	-
CLVOPS	-	-	-	-	-	-	-	-
	1,239,524	**1,623,107**	**1,972,491**	**2,288,933**	**2,601,275**	**2,912,386**	**3,193,874**	**3,456,154**

Public Intervenor
Interrogatory No. 6

Reference: Exhibit C, Schedule 1, Note 9

Interrogatory:

1. Please reconcile the values shown in the "Revenue" block with the values that would result from the product of the Rate and the Throughput blocks. For example, in 2011, the SGSRE rate is $9.5660 per GJ for 246,316 TJ, implying revenues of $2,356,000, whereas revenue is $2,739,000. Conversely, for GS, the implied revenues for 2011 would be $14.5177 * 1,222,376 = $17,746,000, in contrast to the reported $16,690,000. Please provide supporting workpapers for the reconciliation in MS Excel electronic format.

Response:

1. There are two principal reasons why the product of the Rate and the Throughput does not reconcile with the yearly revenue, these are:
   - The impact of the customer or demand charge is not included in the rate, but is included in determination of total revenue. The impact of the customer or demand charge on total revenue will also be affected by the timing of when the customer is attached to the system during the year.
   - The timing of when the rate indicated is forecast to take effect within the year. EGNB has not assumed in the first two years that the rates would take effect at the beginning of the year due to allowing for regulatory approval of any rate changes.

   Please see the attached tables that provide a reconciliation of the revenue values for 2010 to 2015, where 2010 and 2011 have been calculated on a monthly basis and 2012 to 2015 have been calculated on an annual basis. To ensure the reconciliation balances with the forecast revenues, a miscellaneous revenue line has been included. This was necessary due to minor variances in the assumptions applied to different components of the forecast model, due to the evolution of the model over a period of time, that were not identified and made consistent prior to finalization.

Public Intervenor
<u>Interrogatory No. 7</u>

Reference: Exhibit A, Page 7

Interrogatory:

1. Please estimate the impact on the gas commodity price forecast used in the 10-year financial forecast if a significant percentage of gas is backhauled from the U.S.

2. If backhauls are necessary to meet New Brunswick load growth, would EGNB expect the local gas price to rise to the delivered price of backhauled gas? Please explain your response.

Response:

1. Current EGNB gas costs are reflective of gas travelling from the Sable Off-shore Energy Project (SOEP) through Canada toward the U.S. market and are based on a US (Dracut) market price. Any negative impact on the gas commodity price to EGNB as a result of backhauling gas from the U.S. would be equal to the cost of transportation from EGNB's physical receipt point in the US from its supplier(s) to New Brunswick using the least expensive (firm) pipeline system available. Currently this would equate to approximately $0.60 / GJ.

2. If New Brunswick demand for natural gas exceeds the amount being produced by current (and future) Atlantic Canadian supply sources, EGNB does expect the local market price of gas to increase. The extent to which it mirrors the price of backhaul gas is a function of local supply availability (in New Brunswick) versus transportation capacity to deliver gas to (or from) New Brunswick. A supplier will typically look to maximize the value it can receive for its gas in comparison to the supply alternatives that are available to customers.

Public Intervenor
Interrogatory No. 8

Reference: Exhibit C, Schedule 1, Page 12 and Schedule 2, Page 6

Interrogatory:

1. Please segregate the sales & marketing forecast into incentives and other sales & marketing.

2. Please provide detail regarding the distribution O&M expense, for both expense and capitalization percentage.

3. Are installation services expenses included in O&M expense (as suggested in Exhibit C, Schedule 2, page 6)? If so, please segregate those expenses as part of your response to part (b) of this interrogatory.

4. Please provide the decision rule for capitalizing O&M expense in each forecast year.

5. Please explain why EGNB does not plan to continue to capitalize some or all incentives costs after 2012.

6. Please specify which costs are capitalized to Property, Plant & Equipment, and which are capitalized to Development O&M. Please provide the basis for this policy.

7. Please explain in more detail how EGNB plans to reduce its incentives and sales/marketing expenses in 2016.

Response:

1. The following table provides the requested segregation:

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Sales & marketing										
Incentives	6,408	6,170	6,629	6,134	5,598	5,111	1,039	980	930	890
Other sales & marketing	2,867	3,050	3,129	3,217	3,298	3,381	3,466	3,553	3,643	3,735
	9,274	9,220	9,758	9,351	8,896	8,492	4,504	4,533	4,573	4,625

2. The following table provides the requested detail regarding Distribution and Maintenance O&M expenses:

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Distribution & Maintance										
Operations										
Attachments	359	397	413	427	442	458	474	491	508	526
Construction & Maintenance	1,940	2,048	2,001	2,045	2,101	2,159	2,023	2,080	2,139	2,200
Engineering Quality & Assurance	257	266	274	281	289	297	305	314	322	331
Logistics	872	898	923	951	981	1,004	1,029	1,076	1,109	1,136
Planning & Technical Services	713	713	733	756	780	805	830	857	884	912
	4,140	4,323	4,344	4,461	4,594	4,722	4,661	4,817	4,962	5,105
Installation Services										
Installations	814	882	897	928	953	983	1,014	1,047	1,085	1,114
Service	1,058	1,124	1,232	1,259	1,289	1,329	1,370	1,412	1,456	1,502
	1,872	2,006	2,130	2,187	2,242	2,312	2,384	2,459	2,541	2,616
Total Distribution & Maintenance O&M	6,012	6,329	6,473	6,648	6,836	7,034	7,046	7,276	7,503	7,721
Capitalization percentages										
Operations	75%	67%	59%	35%	35%	35%	35%	35%	35%	35%
Installation Services	100%	81%	62%	5%	5%	5%	5%	5%	5%	5%

3. Installation Services expenses are included in O&M expense. These have been segregated in the response to 2. above.

4. Although progress has been made over the last 10 years, EGNB remains a “greenfield” or “start up” utility in the process of establishing itself in a region where the natural gas industry itself is also “greenfield”. EGNB is not only capital intensive but resource intensive, i.e. compared to a mature utility; it requires a disproportionate amount of resources to develop its physical assets as well as the New Brunswick natural gas industry.

   EGNB breaks its operations and administration functions down into a number of departments to help it better manage its business. In 2001, EGNB completed an internal analysis looking at what amount of O&M should be capitalized and what should be expensed. EGNB evaluated the activities of each of its departments to determine what percentage of each department’s resources were involved in the development of either its plant assets or the New Brunswick natural gas industry and what percentage was involved in serving EGNB’s existing customer requirements. EGNB evaluates these departmental percentages each year as part of its budgeting exercise and makes adjustments where necessary. Once the percentage to be capitalized has been applied to each department’s O&M expenditures for the period in question, EGNB groups the amounts into three categories: Plant Development; Industry Development; and Administration. Once grouped, the Administration category is allocated to Plant Development and Industry Development on a prorata basis. The resulting “Capitalized to:” amount is shown near the bottom of Note 10 of Exhibit C, Schedule 1. This methodology has been reviewed by the Board and its consultants as part of past annual financial reviews.

5. As noted in the response to question 4 above, EGNB is still in its development period. As EGNB matures, less and less of the efforts of its employees will be focused on developing the industry and its physical assets, as they become more focused on existing customers. EGNB assumed in its forecast that as EGNB moves toward a mature state these percentages will decrease and become more in line with what you may expect from a mature utility. As a result, the proportion of incentives to be capitalized was reduced.

6. As noted above in question 4, O&M costs are originally streamed into three categories:

- Plant Development (includes costs that are primarily related to the construction of the distribution system) – These costs are capitalized to Property, Plant & Equipment

- Industry Development (includes costs that are primarily related to the development of the industry) – These costs are capitalized to Development O&M Capitalized Costs

- Administration (includes departmental costs that are in support of direct operations) – These costs are allocated to either Plant or Industry Development based on the percentage each represents of the total expenses for a given period.

The following summarizes the cost centre breakdown for each of the categories:

Plant Development	**Industry Development**	**Administration**
Attachments	Advertising and Promotion	Corporate Administration
Construction and Maintenance	Installation Services	Corporate Management
Engineering Quality and Assurance	Project Management	Customer Care
Logistics	Sales	Financial Reporting
Planning and Technical Services	Training and Service	Gas Supply
Training and Services		Human Resources
		Information Technology
		Regulatory

7. EGNB currently offers incentives to accelerate decision making by potential customers in support of developing the natural gas industry in New Brunswick. EGNB expects that once the Development Period has ended, the use of incentives will change. While growth will continue to be important, this growth is expected to occur through more traditional marketing activities seen in mature utilities, reducing the reliance on incentives as a tool to achieve growth. As a result, EGNB has reduced its expected expenditures related to incentives in 2016, the year in which the forecast would project the Development Period to have ended.

Public Intervenor
Interrogatory No. 9

Reference: Financial Statements of the Limited Partnership and Equity Investment

Interrogatory:

1. For each year of operation, please provide the audited financial statements of Enbridge Gas New Brunswick Limited Partnership.

2. For each year of operation, please provide details of the equity invested in the limited partnership. These details should include the timing of the equity investment, the amount invested, and the source of the investment.

Response:

1. EGNB does not believe the historical audited financial statements of Enbridge Gas New Brunswick Limited Partnership are relevant to the determination of the cost of capital or the review of EGNB's 10 year forecast. As a result, EGNB is not providing the requested statements.

2. The following table provides the requested information:

Year	Timing	Amount	Source
2009	N/A	$-	N/A
2008	June 2008 to July 2008	$30.0 million	Enbridge 71%/Non-Enbridge Existing 26%/New 3%
2007	June 2007 to July 2007	$30.0 million	Enbridge 70%/Non-Enbridge Existing 23%/New 7%
2006	N/A	$-	N/A
2005	Aug 2005 to Nov 2005	$70.3 million	Enbridge 64%/Non-Enbridge Existing 12%/New 24%
2004	N/A	$-	N/A
2003	N/A	$-	N/A
2002	N/A	$-	N/A
2001	N/A	$-	N/A
2000	June 2000	$52.0 million	Enbridge 64%/Non-Enbridge 36%

Public Intervenor
Interrogatory No. 10

Reference: Ownership Structure, ROE, Interest Coverage, and Cost of Debt

Interrogatory:

1. Please provide a table indicating Enbridge Inc's ownership structure, all the operating subsidiaries owned by it and which subsidiaries raise debt on the strength of their independent bond ratings and which rely upon debt mirrored down from the parent.

2. Please provide the allowed and earned return on common equity (ROE) for EGNB for each year since NBPUB 299 and the overall utility cost of capital (weighted average of the ROE and debt cost using book value weights).

3. Please provide the interest coverage and cash flow to debt ratios for each year since NBPUB 299 and explain how the ratios are calculated and whether they are approximately consistent with the way that DBRS would calculate them.

4. Please provide the cost of Enbridge's debt used to calculate EGNB's debt cost for each year and how that cost was determined.

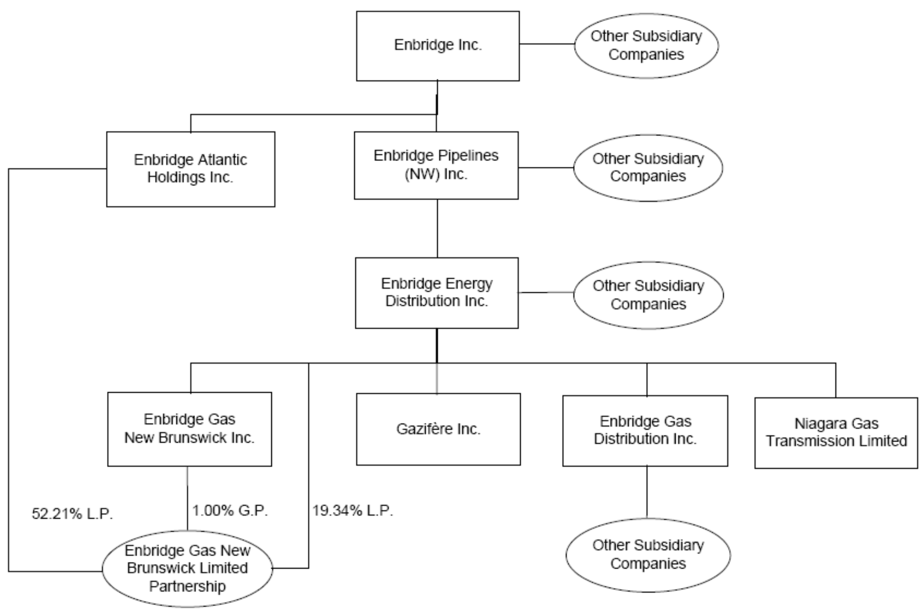
Response:

1. Enbridge Inc. is a publicly traded company with a broad group of investors as shareholders. Enbridge Inc. has many subsidiaries, with many intercompany financing arrangements. The subsidiaries that raise debt on the strength of their independent bond ratings are as follows:
   - Enbridge Pipelines Inc.
   - Enbridge Gas Distribution Inc.
   - Enbridge Income Fund
   - Enbridge Energy Partners, L.P.

   The primary subsidiary where debt is 'mirrored' down from the parent is Enbridge Gas New Brunswick.

   The following chart shows Enbridge Inc.'s ownership of Enbridge Gas New Brunswick:

Enbridge Gas New Brunswick Inc.
Subsidiary & Affiliate Companies



2. The following table provides the requested information:

	EGNB		
	Allowed ROE	Actual ROE	Weighted Average Cost of Capital
2000	13.000%	n/a [1]	10.400%
2001	13.000%	13.000%	10.340%
2002	13.000%	13.000%	10.290%
2003	13.000%	13.000%	10.070%
2004	13.000%	13.000%	9.160%
2005	13.000%	13.000%	9.530%
2006	13.000%	13.000%	9.740%
2007	13.000%	13.000%	9.700%
2008	13.000%	13.000%	9.710%
2009	13.000%	13.000%	9.750%

[1-] In 2000, EGNB did not have Rate Base for regulatory purposes, as it was not operational, therefore no actual ROE

3. The following table provides the requested interest coverage and cash flow to debt ratios:

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
EBITDA										
Reg ROE	$ -	$ 2,126	$ 4,706	$ 6,455	$ 6,591	$ 10,384	$ 14,551	$ 17,707	$ 21,205	$ 24,364
Amortization of PP&E	$ -	$ 255	$ 1,160	$ 1,558	$ 2,545	$ 2,873	$ 3,422	$ 3,622	$ 4,992	$ 5,034
Amortization of Def Dev Costs	$ -	$ 2,236	$ 3,031	$ 3,141	$ 2,968	$ 3,478	$ 1,945	$ 1,558	$ 2,133	$ 2,898
Interest	$ -	$ 1,256	$ 2,802	$ 4,139	$ 6,526	$ 6,945	$ 7,413	$ 9,219	$ 10,681	$ 12,354
Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferral	$ (145)	$ (9,207)	$ (15,169)	$ (17,291)	$ (19,309)	$ (22,163)	$ (18,884)	$ (15,741)	$ (14,969)	$ (22,494)
	$ (145)	$ (3,334)	$ (3,470)	$ (1,998)	$ (679)	$ 1,517	$ 8,447	$ 16,365	$ 24,042	$ 22,156
Interest	$ -	$ 1,256	$ 2,802	$ 4,139	$ 6,526	$ 6,945	$ 7,413	$ 9,219	$ 10,681	$ 12,354
Interest Coverage Ratio	**#DIV/0!**	**(2.65)**	**(1.24)**	**(0.48)**	**(0.10)**	**0.22**	**1.14**	**1.78**	**2.25**	**1.79**

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Operating Cashflow										
Reg ROE	$ -	$ 2,126	$ 4,706	$ 6,455	$ 6,591	$ 10,384	$ 14,551	$ 17,707	$ 21,205	$ 24,364
Deferral	$ (145)	$ (9,207)	$ (15,169)	$ (17,291)	$ (19,309)	$ (22,163)	$ (18,884)	$ (15,741)	$ (14,969)	$ (22,494)
Amortization of PP&E	$ -	$ 255	$ 1,160	$ 1,558	$ 2,545	$ 2,873	$ 3,422	$ 3,622	$ 4,992	$ 5,034
Amortization of Def Dev Costs	$ -	$ 2,236	$ 3,031	$ 3,141	$ 2,968	$ 3,478	$ 1,945	$ 1,558	$ 2,133	$ 2,898
AFUDC	$ -	$ -	$ (158)	$ (102)	$ (281)	$ (106)	$ (104)	$ (70)	$ (29)	$ (34)
	$ (145)	$ (4,590)	$ (6,430)	$ (6,239)	$ (7,486)	$ (5,534)	$ 930	$ 7,076	$ 13,332	$ 9,768
Total Debt	$ 12,063	$ 32,413	$ 45,913	$ 72,913	$ 107,913	$ 101,650	$ 122,650	$ 151,650	$ 166,650	$ 212,650
Cash flow to Debt Ratio	**-1%**	**-14%**	**-14%**	**-9%**	**-7%**	**-5%**	**1%**	**5%**	**8%**	**5%**

The interest coverage has been determined by dividing Earnings before interest, tax depreciation and amortization (“EBITDA”) by interest costs. The cash flow to debt ratio has been determined by calculating total operating cash flow as a percentage of total debt.

EGNB does not have knowledge of the manner in which DBRS would calculate these ratios. However, these ratios are fairly standard financial ratios so EGNB expects they would be consistent with the manner in DBRS would calculate them.

4. Enbridge Inc’s cost of borrowing is assessed and changes each time a debt note is issued, and not on an annual basis. Enbridge Inc’s cost of debt is evaluated and provided to EGNB at the time the long term debt note is being established. The rate is calculated by taking the Bank of Canada 10 year bond yield rate at that time and adding the average indicative Mid-Term Note (“MTN”) spreads for Enbridge Inc. for 10 year bonds.

The table below summarizes Enbridge Inc’s cost of debt for each debt note, as well as the weighted average Enbridge Inc. cost of debt for the years 2000-2009 inclusive.

Promissory Note		Enbridge Inc.'s
Issue Date	**Maturity Date**	**Cost of Debt**
29-Jun-00	30-Jun-10	6.80%
28-Sep-00	30-Jun-10	6.80%
6-Feb-01	6-Feb-11	6.33%
16-Jul-01	18-Jul-11	6.81%
27-Dec-01	28-Dec-11	6.25%
28-Jun-02	29-Jun-12	6.08%
23-Dec-02	24-Dec-12	6.50%
26-Jun-03	27-Jun-13	5.62%
30-Dec-03	30-Dec-13	5.34%
23-Mar-04	24-Mar-14	5.33%
30-Nov-04	28-Nov-14	5.69%
30-Mar-05	30-Mar-15	5.04%
28-Dec-05	28-Dec-15	4.59%
19-Dec-06	19-Dec-16	4.82%
20-Dec-07	20-Dec-17	5.54%
19-Dec-08	19-Dec-13	6.85%
25-Jun-09	25-Jun-14	4.37%
9-Dec-09	9-Dec-19	4.63%

Public Intervenor
Interrogatory No. 11

Reference: Exhibit C, Schedule 1

Interrogatory:

1. Please provide the exact same data as in Exhibit C Schedule 1 for the years since NBPUB 299 in an identical format in an Excel spreadsheet including all formulae.

2. Please provide the exact same data as in Exhibit C Schedule 1 since NBPUB 299, assuming 40% common equity and allowed ROEs of 8.50%, 9.50%, 10.50% and 11.50%.

3. Please provide the exact same data as in Exhibit C Schedule 1 (10 year forecast) assuming 40% common equity and allowed ROEs of 8.50%, 9.50%, 10.50% and 11.50%.

4. Please provide the cash flow statement for Schedule C which matches the income statement and balance sheet both for the ten year forecast period and since NBPUB 299.

5. In the cash flow statement in 3) please itemize as far as possible all amounts that would be regarded as the direct cost of service for existing customers and those that are specific to the development period and have been capitalized.

Response:

1. The Excel spreadsheet supporting the response to Public Intervenor Interrogatory No. 1(2) is attached.

2. Completing this request would require EGNB to regenerate all of its financial statements for each year since 2000 for each of the requested scenarios. EGNB does not believe this request to be reasonable or relevant as it calls for historic hypotheticals.

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 if he desires based on EGNB's response to 1. above.

4. The requested cash flow statements are attached.

5. EGNB assumes the question is intended to reference question 4. EGNB does not keep information in this manner and as a result is unable to provide the requested information.

Public Intervenor
Interrogatory No. 12

Reference: Customer Class Revenues

Interrogatory:

1. Please provide a breakdown of the number of customers, GJ of throughput and dollar value of distribution revenues of EGNB for each of the three major customer classes, that is, residential, commercial and industrial, since NBPUB 299 both in absolute terms and relative to the forecast at that time.

2. Please discuss the changes in the customer breakdown in (1) above and the underlying reasons.

3. Please provide a current and forecast cost comparison of natural gas against the major alternative fuels for EGNB's industrial, commercial, and residential customers.

Response:

1. EGNB is unable to provide the requested breakdown as it has not grouped it customers on this basis since NBPUB 299. Until 2007, residential customers were grouped with small commercial customers. Also, EGNB does not segregate its customers in the general service rate classes between commercial and industrial.

2. Please see the response to 1. above.

3. The current and forecast cost comparison for residential customers would be seen in the derivation of the SGSRE and SGSRO rates found in the response to Public Intervenor Interrogatory No. 3. EGNB cannot provide a comparison for commercial and industrial customers as it does not establish delivery rates on this basis. The derivation of delivery rates found in the response noted above provides the only basis of comparison that EGNB has.

Public Intervenor
<u>Interrogatory No. 13</u>

Reference: Business Risk

Interrogatory:

1. Please provide copies of the sections of any security analyst reports for EGNB's parent that discuss EGNB's business risk since NBPUB 299.

2. Please provide copies of all presentation materials provided to DBRS and any other rating agency that discuss EGNB's business risk and its impact on its parent's bond rating since NBPUB.

3. Please provide copies of any credit analyst reports that discuss EGNB's contribution to its parent's bond rating since NBPUB 299.

4. Please provide copies of all material change reports or other filings that EGNB's parent has made with any securities regulators discussing the business risk of EGNB since NBPUB 299.

5. Please provide copies of the MD&A sections of EGNB's parent's financial statements that discuss EGNB since NBPUB 299.

Response:

1. Since there are a large number of security analyst reports, a sample of analyst reports for Enbridge Inc. were reviewed by the Enbridge Inc. Treasury group and no material reference to EGNB's business risk was contained in these reports. Because of the regulated nature of EGNB's business and the immateriality of EGNB's contribution to the overall cash flows and profitability of Enbridge Inc., the Treasury group believes there have been no material discussions of EGNB's business risk in Enbridge Inc. analyst reports since NBPUB 299.

2. Please see the attached excerpt from the presentation provided to DBRS, S&P and Moody's for Enbridge Inc.'s 2009 review. The information does not discuss EGNB's business risk or its impact on Enbridge Inc.'s bond rating. Because of the regulated nature of EGNB's business, the Enbridge Inc. Treasury group is confident that since NBPUB 299 there would not have been previous discussions of EGNB business risk impacting Enbridge Inc.'s credit rating.

3. Please see the attached most recent Enbridge Inc. credit analyst reports from DBRS, S&P and Moody's, in which there is no material mention of the operations of EGNB. The Enbridge Inc. Treasury group is confident that there would not have been reference to EGNB contributing to Enbridge Inc.'s bond rating in similar reports since NBPUB 299.

4. To the best of the Enbridge Inc. Treasury group's knowledge, there have been no material discussions of EGNB business risk in filings with any security regulators since NBPUB 299.

5. Please see the attached 2009 Enbridge Inc. MD&A. Specific references to EGNB are made on page 31 of the MD&A. The Enbridge Inc. Treasury group is confident that past disclosure, if any, would have been similar and would not have extensively referenced EGNB since NBPUB 299.

Public Intervenor
Interrogatory No. 14

Reference: Rate Design and Amortization

Interrogatory:

1. Please indicate the breakdown of the average rate for each customer class in terms of a fixed demand charge and a variable charge based on use used to generate the forecast in Exhibit C Schedule 1.

2. Please discuss any significant changes in the rate design used by EGNB in developing its ten year forecast and provide an explanation for the change.

3. Please provide a table with the amortization rate for the major classes of assets as well as the composite depreciation rate used for each in the ten year forecast.

Response:

1. EGNB has not used an average rate for each customer class to generate the forecast in Exhibit C, Schedule 1. The customer and demand charge components were calculated separately from the volume based delivery charge. EGNB assumed that the existing customer and demand charge rates would remain unchanged during the forecast period.

2. EGNB has not assumed any changes from the market-based rates formula approved by the Board on May 26, 2009 in developing its ten year forecast. Also, see the response to Board Interrogatory No. 4(7).

3. The following table provides the amortization rates for the major classes of assets:

Distribution Plant - Services	3.83%
Distribution Plant - Mains	2.43%
Deferred O&M Asset	2.43%
District Meas. & Reg'g Equip	3.83%
Stations	4.40%
Lease Improvements	Leasehold improvements are amortized over the term of the related lease
Office Furniture	4.40%
Tools and Work Equipment	5.30%
EGNB Transportation	11.80%
Communications Equipment	28.80%
Computer Equipment	28.80%
Computer Software	28.80%
Franchise Fee	20 years
Deferred Equity Call costs	5 years
Term Deposit	n/a
Regulatory Deferral	30 years

EGNB does not understand what the term "composite depreciation rate" refers to, but notes that the amortization rates listed above were used for each year of the forecast.

Public Intervenor
Interrogatory No. 15

Reference: EGNBLP Gas Supply

Interrogatory:

1. Please provide a brief overview discussion of the sources of EGNB's gas supply and the contracts that underpin that supply including:
   i. The forecast production of the major supply basin (SOEP) over the next ten years;

   ii. The optionality involved in sourcing from an LNG plant;

   iii. What would be involved in backhauling supply from the US; and

   iv. The forecast production from Deep Panuke over the next ten years.

2. Please provide a system map showing the EGNB system and how it interconnects with the pipelines and supply fields discussed on pages 6-7 of Mr. Charleson's testimony.

Response:

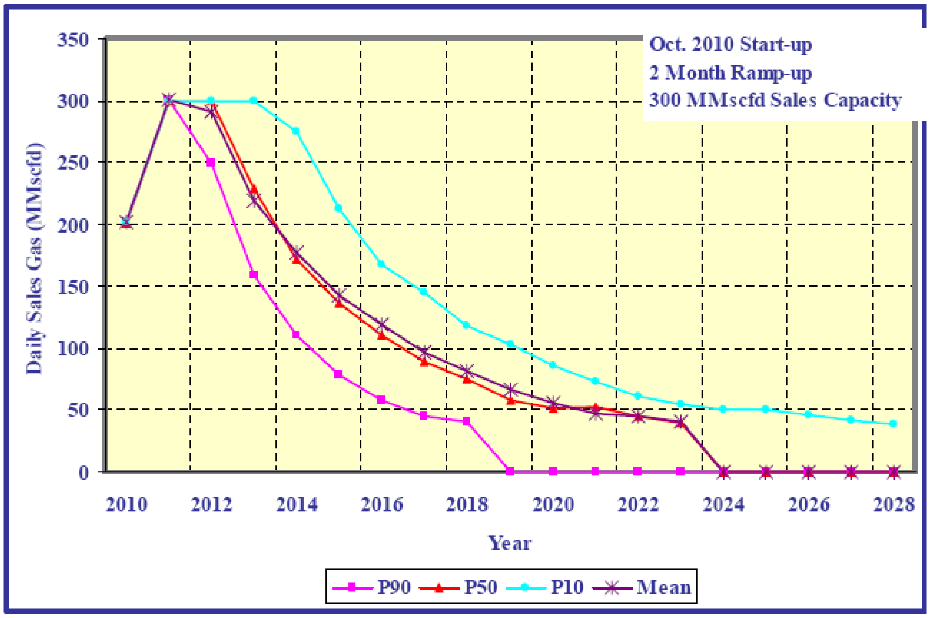
1. EGNB currently sources 100% of its gas from the major supply basin (SOEP). Current natural gas supply arrangements for EGNB extend for as many as three years.

   i. Production forecasts for SOEP are not available in the public domain. Current production levels from SOEP are approximately 350,000 MMBtu/d while the field is expected to remain in service through the second half of this decade.

   ii. At this point, EGNB does not have a direct interconnection with the sole operating LNG terminal in Atlantic Canada. EGNB can however, purchase supply from this terminal using the same purchasing methods used for all other gas purchases. Should EGNB choose this supply option, there may be increased gas costs due to the necessary backhaul of such gas from the US purchase location to the Canadian market.

   iii. If EGNB were to backhaul gas supply from the US into Canada to meet market demand, outside of United States federal and State legal requirements for import/export reporting, EGNB would need to contract for capacity on the M&NP US system. EGNB would also need to ensure that all necessary contracts were in place to transact with parties doing business at desired points of purchase along the M&NP US system.

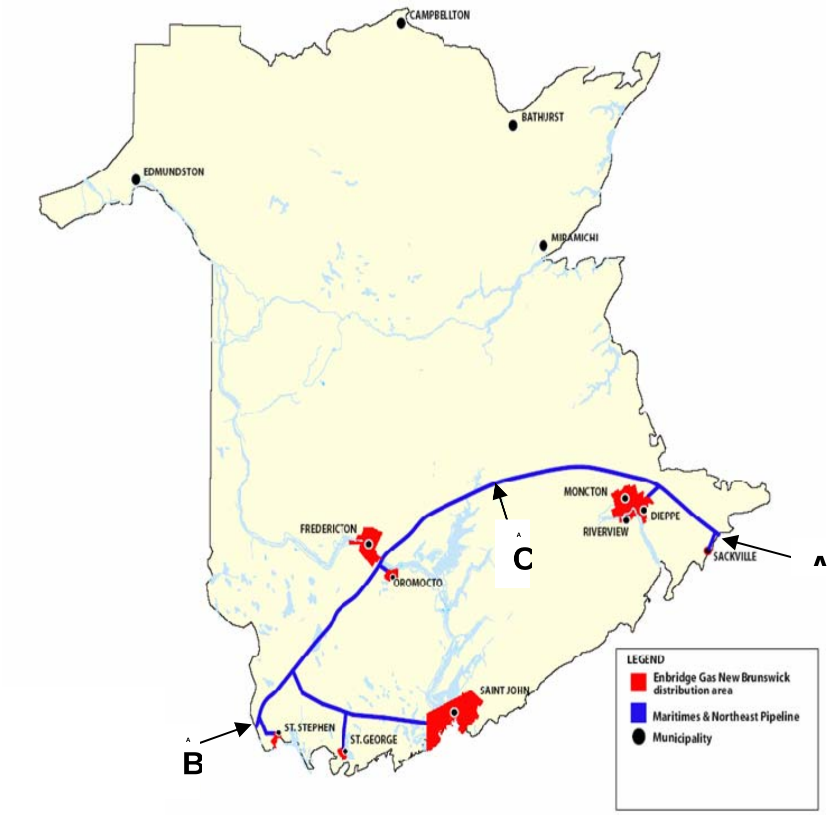
   iv. The following graph from Encana's Deep Panuke application to the NEB (page 2-4) in November 2006 shows Encana's forecasts production from Deep Panuke at the time of their application:



EGNB is not aware of any more recent public information regarding Deep Panuke production. EGNB notes that Deep Panuke is not currently planning to come online in October 2010.

2. The requested map is provided below where:
    - "A" represents where SOEP supply flows into the Maritimes & Northeast Pipeline (M&NP) system in New Brunswick and where EGNB expects Deep Panuke supply to flow into the Province.
    - "B" represents where backhaul supply would flow into New Brunswick and also where Canaport LNG supply would need to flow into the M&NP system, as EGNB has no interconnections with the Emera Brunswick Pipeline.
    - "C" represents where Corridor Resources supply enters the M&NP system.

    In all cases, EGNB would rely on its interconnections with the M&NP system for moving supply into its distribution system.


CAMPBELLTON
BATHURST
EDMUNDSTON
MIRAMICHI
MONCTON
DIEPPE
RIVERVIEW
FREDERICTON
OROMOCTO
SACKVILLE
C
B
SAINT JOHN
ST. STEPHEN
ST. GEORGE
LEGEND
Enbridge Gas New Brunswick distribution area
Maritimes & Northeast Pipeline
Municipality

Public Intervenor
Interrogatory No. 16

Reference: Exhibit B - Fixed Versus Floating ROE

Interrogatory:

1. Please discuss whether Ms. McShane in 1999 and today was asked to comment on the reasonableness of EGNB's suggested ROE and capital structure or whether she was given a clean sheet of paper to come up with her own recommendations without input from EGNB.

2. If EGNB indicated to Ms. McShane their requested financial parameters, please indicate in what way Ms. McShane's recommendations in 1999 and today deviated from the suggestions of EGNB.

3. In similar testimony for other companies around 1999, Ms. McShane recommended a "floating" ROE that would adjust by 75% of the forecast changes in long Canada bond yields. Please explain why, for EGNB in 1999, she recommended a fixed ROE?

4. In 2005 Ms. McShane recommended the NEB formula ROE for the Mackenzie Valley Pipeline (MVP) plus a premium where the ROE adjusted by 75% of the change in the forecast long Canada bond yield. Further Ms. McShane used EGNB as a reference point for a similar "greenfield" utility. Why would Ms. McShane judge EGNB to warrant a fixed ROE versus a floating rate for MVP? What are the key differentiating features between these two different recommendations?

5. Would Ms. McShane agree that a "locked" in fixed ROE involves interest rate risk similar to a long bond, whereas a floating ROE does not? If so how much is the risk premium embedded in the recommended fixed rate ROE that would be removed should EGNB be put on an ROE formula similar to the one she recommended for MVP?

6. Please provide the 2011 allowed ROEs for the other Canadian utilities and pipelines part of Enbridge Inc's portfolio and the method by which their ROEs are currently calculated.

Response:

1. In 1999, Ms. McShane was asked to evaluate the reasonableness of the proposed ROE, capital structure and cost of debt within the context of the regulatory framework that EGNB was proposing and which formed part of the "essential elements" agreed to by the Province of New Brunswick in awarding the initial franchise for gas distribution. For purposes of this proceeding, Ms. McShane was asked to make independent recommendations for these three elements of the cost of capital.

2. Please see the response to 1. above.

3. Ms. McShane did not recommend a fixed ROE; the fixed ROE was part of the essential elements that Ms. McShane evaluated.

4. Ms. McShane did not recommend either the proposed ROE or the formula for Mackenzie Valley Pipeline (MVP). The proposals had been made by MVP. Ms. McShane was asked to evaluate their reasonableness. With respect to the fixed rate for EGNB, please see response to part 3.

5. Note that Ms. McShane did not recommend a formula for MVP; the pipeline sponsors proposed a formula. In principle, a return on equity that is locked in entails risk that the cost of equity will rise while the allowed ROE equity does not, whereas an ROE that tracks the cost of equity over time does not entail that risk. The extent to which a premium might be warranted for a locked in ROE depends on various factors including (a) the length of time over which the ROE is locked in and (b) the specifics of the formula to which the utility might otherwise be subject. In respect to the latter, the underlying premise is that the relevant automatic adjustment formula operates correctly. In EGNB's case, while the proposed ROE would be fixed for a period of time, that is, not subject to annual change through the operation of a formula, the fixed ROE would not attract a material (measurable) premium because EGNB's ROE is not contractually locked in (as is the case, for example, for Alliance Pipeline), but can be reconsidered when circumstances so warrant.

6. There have been no 2011 allowed ROEs set for the Canadian utilities and pipelines owned by Enbridge Inc. The following describes the current circumstances for the Canadian utilities and pipelines owned by Enbridge Inc. with respect to allowed ROEs.

   <u>Alliance Pipeline (Canadian portion):</u> Fixed return on equity of 11.26% for fifteen years (through 2015) on initial pipeline investment. As per NEB Decision G-93-97 (November 1998), the target ROE for the new pipeline was 12% with a potential range of 10% to 14%, based on actual construction costs. The 11.26% allowed ROE reflects the impact of the actual construction costs. The ROE applicable to the Alliance expansion approved by the NEB in September 2007 (with no construction cost risk) will be fixed at 11.26% through 2015.

   <u>Enbridge Gas Distribution (EGD):</u> Pursuant to a five-year negotiated incentive plan, the ROE underpinning EGD's rates was fixed for five years at 8.39%. The fixed ROE was based on the outcome for 2007 of the Ontario Energy Board's automatic adjustment formula adopted in 1997, which changed the allowed ROE by 75% of the change in forecast long-term Canada bond yields. Over the five-year period of the plan, Enbridge Gas Distribution is subject to an earnings sharing mechanism, which shares equally with customers earnings in excess of 100 basis points above the formula, as updated each year of the plan. EGD's five year incentive plan expires at the end of 2012.

As discussed at pages 30 and 31, in its Cost of Capital Policy Report issued in December 2009, the Ontario Energy Board has revised both its benchmark ROE and automatic adjustment formula since EGD's five year plan was implemented. The revised formula changes the annual ROE by 50% of the change in forecast long-term Canada bond yields and 50% of the change in the spread between long-term A rated utility bonds and long-term Canada bond yields.

Enbridge Pipelines Core System: Subject to a negotiated settlement for 2010 tolls based on a total revenue requirement; no ROE or capital structure is specified.

Enbridge Pipelines Alberta Clipper and Line 4 Extension: Negotiated settlements for expansions to Mainline system include target ROE equal to the annual NEB multi-pipeline formula result (8.52% for 2010) plus 2.25 percentage points on 45% equity. Actual allowed ROE will reflect impact of construction cost risk assumed by Enbridge Pipelines.

Enbridge Pipelines Line 9: Under previous agreements with shippers, ROE was equal to NEB multi-pipeline ROE on 45% equity. Those agreements have expired and Line 9 has applied to NEB for final tolls for 2008-2010 based on a proposed revised formula for estimating the benchmark NEB-regulated pipeline ROE plus a risk premium for Line 9's incremental risk (requested ROE of 12.21% for 2010 on 55% equity).

Enbridge Pipelines (N.W.): NEB multi-pipeline formula ROE on 55% equity per long-term agreement with shippers.

Enbridge Southern Lights: 10% fixed allowed ROE for 15 years. Original target allowed ROE was 12%, with a potential range of 10.0% to 14.0%, depending on actual construction costs compared to forecast, e.g., lower than forecast would have meant a higher allowed ROE and vice versa. The 10% fixed actual lower than target allowed ROE reflects impact of higher than forecast construction costs.

Gazifère Inc.: Annual ROEs have been subject since 1998 to a formula which changes the allowed ROE by 75% of change in the forecast long-term Canada bond yield. Gazifère has requested a change in its base ROE (to 11.25%) and to the formula. The proposed new formula would change the annual ROE by 50% of the change in forecast long-term Canada bond yields and 50% of the change in the spread between long-term A rated corporate bonds and long-term Canada bond yields.

Public Intervenor
Interrogatory No. 17

Reference: Exhibit B – ROE Adjustment Mechanism

Interrogatory:

1. Please indicate what reviews of formula based ROE adjustment mechanism Ms. McShane has participated in since 1998, prior to the recent financial crisis of 2008/9.

2. Please discuss the results of the reviews of the ROE adjustment mechanism discussed in (1) above.

3. Please indicate whether Ms. McShane was a participant in the Alberta (AEUB) generic hearing that introduced an automatic ROE adjustment mechanism in 2003 and what her recommendations were.

4. Please indicate what the AEUB decision in the generic hearing in (3) above was in terms of a fair ROE.

5. Please confirm that Ms. McShane participated in an Ontario Power Generation hearing where the OEB confirmed the use of its ROE adjustment mechanism and formula in a decision dated November 3, 2008.

6. Please indicate the ROE adjustment formulae in use as of December 31, 2008 by: the National Energy Board, the Ontario Energy Board, the Alberta Energy and Utilities Board, the BC Utilities Commission, the Manitoba PUB, the Regie de L'energie, the Board of Commissioners of Newfoundland and Labrador.

7. Please indicate the ROEs allowed by the formulae referenced in (6) above with Ms. McShane's current forecast long Canada bond yield.

Response:

1. Ms. McShane has participated in the following regulatory proceedings which reviewed the existing formula:

Proceeding /Company	Date of Decision	Benchmark ROE	Benchmark Long Canada	Adjustment Mechanism Adopted
British Columbia Benchmark Utility ROE	Aug-99	9.5%	6.0%	Sliding scale: Fixed risk premium of 350 basis points when Long Canada yield was equal to or less than 6.0%. ROE changes by 80% of change in forecast Long Canada yield when Long Canada above 6.0%. (G-80-99)

Proceeding /Company	Date of Decision	Benchmark ROE	Benchmark Long Canada	Adjustment Mechanism Adopted
Enbridge Gas & Union Gas	Feb-04	10.65% (for EGD)	7.25%	No change in formula (ROE changes by 75% of change in forecast Long Canada yield) (RP-2002-0158)
British Columbia Benchmark Utility ROE	Mar-06	9.145%	5.25%	ROE changes by 75% of change in forecast Long Canada yield (G-14-06)

2. Please see response to 1. above for the base ROEs and adjustment mechanisms adopted.

3. Ms. McShane was a participant in the 2003 Alberta generic proceeding. Her recommended benchmark return on equity was 11.25% at a forecast long Canada yield of 5.75% and a formula adjusting the ROE by 50% of the change in forecast long-term Canada bond yields.

4. The AEUB set the initial ROE at 9.60% at a long-term Canada bond yield of 5.68%, with an automatic adjustment formula adjusting the ROE by 75% of the change in forecast long-term Canada bond yields.

5. It is confirmed.

6. The formulas and indicated returns on equity at a forecast long Canada yield of 5.0% (as per Appendix C, page C-23) using the formulas in force as of December 31, 2008 for the various regulatory boards are presented in the table below:

Regulatory Board	Base Equity Return	Underlying Forecast Long Canada Yield	Adjustment Mechanism 12/31/2008 (% change in ROE for 1% change in Long Canada)	ROE at Long-term Canada of 5.0%	Status of Formula
National Energy Board	12.25%	9.25%	75%	9.06%	Discontinued
Ontario Energy Board	9.35%	5.5%	75%	8.98%	Revised [1/]
Alberta Energy and Utilities Board	9.6%	5.68%	75%	9.09%	Suspended 2010/Under Review
BC Utilities Commission	9.145%	5.25%	75%	8.96%	Eliminated/Report on Alternatives due December 2010

Regulatory Board	Base Equity Return	Underlying Forecast Long Canada Yield	Adjustment Mechanism 12/31/2008 (% change in ROE for 1% change in Long Canada)	ROE at Long-term Canada of 5.0%	Status of Formula
Manitoba PUB	12.12%	9.12%	80%	8.82%	[2/]
Régie de L'énergie (for Gazifère)	10.0%	5.7%	75%	9.48%	Under Review
Board of Commissioners of Newfoundland and Labrador	9.75%	5.6%	80%	9.27%	Renewed April 2010, change from use of actual to forecast bond yields

[1/] Revised as follows: Refined formula-based ROE calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year).

[2/] The formula was established for Centra Gas Manitoba in 1995; the rate base/rate of return methodology was replaced with a net income approach following the company's acquisition by Manitoba Hydro.

7. Please see response to 6. above.

Public Intervenor
Interrogatory No. 18

Reference: Exhibit B – Risk Assessment

Interrogatory:

1. On Page 7, Ms. McShane indicates that the "cost of capital is also a function of financial risk." This statement follows a discussion of business risk. Please indicate which of her estimates for EGNB follows explicitly from a risk assessment of either EGNB or a comparable utility and explain in detail how the risk assessment generates the ROE estimate.

2. More specifically, please indicate how the comparable earnings or DCF estimates explicitly incorporate a risk assessment of EGNB.

3. In Ms. McShane's judgment, how much weight should be placed on estimates that explicitly incorporate risk versus methods that implicitly incorporate risk given her statements on Page 7?

Response:

1. The "from first principles" approach developed an ROE for a benchmark utility using three different risk premium methods and three DCF models. The risk assessment of EGNB was then used to position EGNB relative to the benchmark. The relative risk assessment became the foundation for the selection of a sample of higher risk gas utilities. The betas for this higher risk sample as adjusted for differential financial risk with EGNB were utilized to develop a risk premium specific to EGNB. This analysis was supplemented by an estimate of the incremental risk premium by reference to estimates of the small size premium.

2. There was no comparable earnings estimate, assuming that, by that reference, the question is referring to the traditional comparable earnings test, which estimates the achievable returns on book equity for a sample of unregulated companies whose total risk is determined to be similar to that of a utility. The DCF and the DCF-based equity risk premium tests were applied to a sample of utilities whose total risk was determined to be similar to that of a benchmark utility. The utilities were selected using criteria designed to result in a sample that is of reasonably comparable risk to a benchmark utility. The risk assessment of EGNB was then used, as indicated in response to part 1, as the foundation for the selection of an alternative (higher risk) sample of companies whose betas were used to develop a risk premium specific to EGNB.

3. Ms. McShane assumes that the reference to estimates that "explicitly incorporate risk" is to estimates made by reference to the Capital Asset Pricing Model, or variants thereof, which apply an explicit relative risk adjustment to an estimate of the market return. As indicated in Ms. McShane's testimony at page 37, that "Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is

powerful enough on its own to produce “the number” that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.” In Ms. McShane’s judgment, the various tests that she has relied on to estimate the return requirement for a benchmark utility, including a variant of the Capital Asset Pricing Model (i.e., the risk-adjusted equity market risk premium test), provide different perspectives on the fair return and should be accorded the weights that were relied on in the development of the benchmark utility return on equity.

Public Intervenor
Interrogatory No. 19

Reference: Exhibit B – Stand-Alone Utility.

Interrogatory:

1. Please confirm that the basic theory of regulation is that as far as possible regulation should generate the same minimum average cost results of perfect completion. If not, why not?

2. Please confirm that if a 'stand alone' utility is of such a small size that it would not exist in a competitive market, its costs should not be passed on to ratepayers. If you do not agree, please indicate any economic theory that justifies the idea that regulation should protect utilities that are of an inefficient scale.

3. Further to (3) above, please confirm that the qualification to Ms. McShane's definition of stand-alone on Page 8 is that the utility be of a sufficient scale that it could exist as an independent entity. If not ,please explain in detail why not.

4. Please confirm that scale or size is a factor in bond ratings and financial market access. If not, please indicate any references in bond rating reports that states that size is not a factor in their assessment of the utility's business risk and rating.

5. Please indicate whether a utility that is still in the development phase can be a stand-alone utility given that it is similar to a normal project involving constant investment.

Response:

1. The purpose of regulation is to emulate competition; perfect competition does not exist. The objective is to avoid allowing utilities, which have market power, the ability to collect monopoly profits.

2. Ms. McShane does not agree. Ms. McShane's view is that regulation should allow a regulated company an opportunity to recover its prudently incurred costs, including the cost of capital that it incurs in providing utility service. The return available from the application of invested capital to other enterprises of like risk is one requirement of the fair return standard. This standard is used to determine the cost of capital for a utility. Adherence to the stand-alone principle through capital structure, return on equity, or a combination thereof, for individual segments, divisions, or subsidiaries of a larger company is a means of ensuring that it is the cost of capital related to the risk of the specific investment that is being estimated and passed on to ratepayers.

3. Ms. McShane agrees that, in the application of the stand-alone principle, the ability to actually exist as an independent entity is a reasonable consideration in the estimation of the cost of capital.

4. It is confirmed.

5. As stated in response to 2. above, adherence to the stand-alone principle through capital structure, return on equity, or a combination thereof, for individual segments, divisions, or subsidiaries of a larger company is a means of ensuring that it is the cost of capital related to the risk of the specific investment that is being estimated. This is true whether the utility is in the development stage or has progressed beyond the development stage.

Public Intervenor
<u>Interrogatory No. 20</u>

Reference: Exhibit B – Business Risk and Forecasting

Interrogatory:

1. In her discussion of the business risk of EGNB, Ms. McShane discusses the significant deviations of EGNB's customer base from that originally forecast. However, in Ms. McShane's judgment is EGNB riskier with only 35% of the forecast throughput versus what it would have been with 100% of the forecast throughput? Please discuss in detail.

2. Further to (1) above, if EGNB's forecast had been met, what ROE and common equity ratio would Ms. McShane now be recommending?

3. Further to (1) above, does Ms. McShane regard the current situation as a "worst case scenario" compared to what was thought to be possible in 1999? Please confirm that the 50% common equity ratio and 13% ROE were allowed in NBPUB 299 to reflect the risks involved in the development stage. Further, to what extent would Ms. McShane agree that EGNB has already been compensated for the risks involved in the development stage?

4. Does Ms. McShane judge a utility in a development stage to be inherently riskier than one that is in a mature stage recovering its full rate base costs?

5. Would Ms. McShane agree that risk has now largely been realised even if it has resulted in a worse than expected scenario? If not please discuss in detail.

6. Ms. McShane recommends a 50% common equity ratio and 12.75% ROE. Please indicate the average ROE earned by Corporate Canada over the period 2000-2009, and the average common equity ratio. Please be explicit in the data sources used.

7. Would Ms. McShane regard EGNB as riskier than an average Canadian company? If so, please justify and indicate any other non-ROE regulated Canadian companies that have similar protective mechanisms to EGNB.

Response:

1. Yes, Ms. McShane would judge EGNB to be riskier with only 35% of its forecast throughput than it would be had its original forecasts been met. The original forecasts anticipated that EGNB would have, by 2010, attracted 38,000 customers and had more than 16 PJs of throughput, larger, for example, than Pacific Northern Gas and Gazifère. It would have been able to set rates on a cost of service basis and, while still recovering the accrued revenue deficiency (which had been forecast to peak at $13 million) would no longer have been deferring any part of its allowed rate of return. In other words, while still an immature utility,

EGNB would have moved beyond the development stage and been significantly closer to being a mature utility than it is.

2. Had the forecasts been achieved as anticipated, the recommended ROE and capital structure would have been closer to what she would recommend for a mature gas distribution utility, with due regard for the specific market, competitive, supply and regulatory environment of EGNB. However, the premise of the question is merely hypothetical and Ms. McShane has not undertaken the analysis to determine what the ROE and common equity ratio might be under such hypothetical circumstances.

3. While there is a significant divergence between EGNB's current circumstances and the initial forecasts, Ms. McShane would not characterize the current circumstances as a "worst case" scenario. Ms. McShane agrees that the 13% ROE and 50% common equity ratio were intended to be compensation for the risks faced during the development period, which based on the Board's criteria, has not concluded. As stated in Exhibit B, commencing at line 311, "Effectively, EGNB is experiencing the risks that were envisioned at its inception, which, in turn, have resulted in the magnitude of the revenue deficiency deferral account, for which investors are at risk of recovery. While the risks have shifted over time from market development to recovery of the invested capital, I see no reason that either existing or prospective investors would require a lower incremental risk premium to compensate for the risk than was incorporated in the ROE adopted in 2000, estimated at 200 to 300 basis points above the returns for mature gas distribution utilities."

4. Yes.

5. No. Please see response to 3. above.

6. Based on surveys, Statistics Canada estimates the ROE and debt/equity ratio quarterly for Canadian enterprises. Based on the annual data reported by Statistics Canada in the *Canadian Economic Observer* (June 2010 and historical tables), the average ROE for all industries for the period 2000-2009 was 10.3%. Based on the quarterly data reported by Statistics Canada in *Quarterly Financial Statistics for Enterprises,* the average reported debt/equity (debt as a percent of equity) ratio was approximately 85%; the corresponding equity/capital ratio (equity as a percent of debt plus equity) is approximately 55%.

7. No. However, higher risk companies do not always earn higher returns, either returns on book value or market returns, than lower risk companies. If they did, they would not be considered risky. To illustrate, I selected a sample of relatively low risk unregulated firms based on the following criteria:

   - Listed on the TSX, domiciled in Canada and not structured as an income trust.

   - Limited to industries characterized by relatively stable demand. Categorized in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples. Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

- Have earnings data available and positive equity since 1999.
- Have at least five years of market data available (sufficient to calculate a five-year beta).
- Have paid dividends each year since 2000.
- Stock is ranked Very Conservative or Conservative by the Canadian Business Service (CBS).
- If debt is rated by either DBRS or Standard & Poor's, debt ratings are investment grade, i.e., BBB (low) or BBB- respectively.
- Five-year beta ending 2009 is below the market average beta of 1.0.

The following table indicates that the returns on common equity for this sample of relatively low risk unregulated firms averaged approximately 11.0% to 12.0% from 2000-2009:

**RETURNS ON AVERAGE COMMON STOCK EQUITY FOR
20 LOW RISK UNREGULATED CANADIAN COMPANIES**

Company Name	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**Average 2000-2009**
ALGOMA CENTRAL CORP	1.1	14.8	9.3	4.7	9.2	11.2	13.4	15.1	10.3	8.8	9.8
ARBOR MEMORIAL SERVICES-CL B	7.5	5.1	14.5	19.7	13.0	10.6	10.5	9.6	9.9	10.2	11.1
ASTRAL MEDIA INC -CL A	4.4	8.2	10.0	10.0	10.9	12.1	13.1	13.0	14.7	-12.6	8.4
CANADA BREAD CO LTD	7.4	8.6	13.9	9.6	14.3	14.5	9.5	13.7	9.7	10.6	11.2
CANADIAN NATIONAL RAILWAY CO	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	18.3	17.0	16.3
CANADIAN PACIFIC RAILWAY LTD	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	10.8	9.6	13.3
CANADIAN TIRE CORP -CL A	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	11.2	9.2	12.2
COGECO INC -SUB VTG	3.5	25.3	12.5	2.9	-3.1	-6.3	7.4	21.0	6.2	-20.6	4.9
EMPIRE CO LTD -CL A	69.1	16.4	11.4	11.6	11.4	16.2	10.3	14.0	10.5	10.3	18.1
JEAN COUTU GROUP	14.9	15.7	16.6	16.2	8.9	6.6	8.0	-14.3	-122.9	23.3	-2.7
LOBLAW COMPANIES LTD	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	9.6	10.8	12.5
MAGNA INTERNATIONAL -CL A	15.9	14.7	11.8	9.5	13.3	10.5	7.7	7.8	1.0	-6.2	8.6
MAPLE LEAF FOODS INC	8.0	10.3	12.2	4.8	13.0	9.9	0.5	19.2	-3.2	4.5	7.9
METRO INC -CL A	22.8	24.1	23.9	23.8	21.0	16.1	15.6	15.1	14.7	16.4	19.4
SAPUTO INC	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	15.5	19.1	17.5
SHAW COMMUNICATIONS INC-CL B	5.5	-8.4	-14.1	-4.5	2.8	7.7	27.2	20.4	31.6	22.5	9.1
THOMSON-REUTERS CORP	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	9.1	4.0	11.9
TORSTAR CORP -CL B	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3	-22.7	5.3	6.2
TRANSCONTINENTAL INC -CL A	13.7	4.0	18.9	17.5	13.9	13.3	12.2	10.3	0.7	-7.7	9.7
WESTON (GEORGE) LTD	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	17.5	17.6	14.9
Mean	**14.6**	**11.0**	**13.0**	**12.3**	**12.2**	**11.8**	**11.1**	**13.9**	**2.6**	**7.6**	**11.0**
Median	**14.1**	**12.0**	**13.2**	**11.4**	**13.0**	**13.1**	**10.8**	**14.1**	**10.1**	**9.9**	**11.1**
Average of Annual Medians											**12.2**

Source: Standard and Poor's Research Insight.

As the following table shows, the common equity ratios of these companies averaged over 60% over the period 2000-2009:

RISK MEASURES FOR 20 LOW RISK UNREGULATED CANADIAN COMPANIES

	Debt Ratings			Beta 2005-2009		2000-2009 Average Equity Ratio
Company Name	**S&P**	**DBRS**	**CBS Stock Rating**	**Raw**	**Adjusted**	**Based On Total Capital**
ALGOMA CENTRAL CORP			Very Conservative	0.90	0.93	84.2%
ARBOR MEMORIAL SERVICES-CL B			Conservative	0.27	0.51	67.2%
ASTRAL MEDIA INC -CL A			Very Conservative	0.55	0.70	89.7%
CANADA BREAD CO LTD			Conservative	0.58	0.72	85.9%
CANADIAN NATIONAL RAILWAY CO	A-	A (low)	Very Conservative	0.47	0.64	58.7%
CANADIAN PACIFIC RAILWAY LTD	BBB	BBB	Very Conservative	0.76	0.84	55.6%
CANADIAN TIRE CORP -CL A	BBB+	A (low)	Very Conservative	0.53	0.68	64.6%
COGECO INC -SUB VTG			Very Conservative	0.88	0.92	26.8%
EMPIRE CO LTD -CL A			Very Conservative	0.16	0.44	59.8%
JEAN COUTU GROUP			Conservative	0.51	0.67	70.4%
LOBLAW COMPANIES LTD	BBB	BBB	Very Conservative	0.32	0.55	52.6%
MAGNA INTERNATIONAL -CL A	BBB	BBB (high)	Conservative	0.79	0.86	86.3%
MAPLE LEAF FOODS INC			Very Conservative	0.14	0.42	47.7%
METRO INC -CL A	BBB	BBB	Very Conservative	0.16	0.44	76.2%
SAPUTO INC			Very Conservative	0.24	0.49	71.5%
SHAW COMMUNICATIONS INC-CL B	BBB-	BBB	Very Conservative	0.36	0.57	38.6%
THOMSON-REUTERS CORP	A-	A (low)	Very Conservative	0.38	0.58	68.7%
TORSTAR CORP -CL B		BBB	Conservative	0.52	0.68	58.5%
TRANSCONTINENTAL INC -CL A	BBB-	BBB (high)	Very Conservative	0.80	0.86	63.4%
WESTON (GEORGE) LTD	BBB	BBB	Very Conservative	-0.14	0.24	36.6%
Mean	**BBB**	**BBB(high)**	**Very Conservative**	**0.46**	**0.64**	**63.1%**
Median	**BBB**	**BBB**	**Very Conservative**	**0.49**	**0.66**	**64.0%**

Source: Standard and Poor's Research Insight, DBRS and The Blue Book of CBS Stock Reports.

Public Intervenor
<u>Interrogatory No. 21</u>

Reference: Exhibit B – Trends in Equity Ratios

Interrogatory:

1. On Page 16, Ms. McShane notes that there has been an upward trend in common equity ratios since 2000.

   i. Please indicate any changes business risk that would support an upward change, please be specific;

   ii. Please indicate any regulatory changes that would support an increase in common equity ratios, for example, would the removal of non-monopoly elements such as water heaters or energy purchases support an increase or a decrease?

2. Can Ms. McShane point to any objective risk assessments, such as betas, standard deviation of returns, inability to earn the allowed ROE, etc. that would support an increase in utility risk since 2000?

3. Please provide a copy of the Nova Scotia Utility and Review Board (NSUARB) Decision of February 2009 for Heritage Gas.

Response:

1.

   i. To Ms. McShane's knowledge, the only increases in the allowed common equity ratios reported on Table 2 that were explicitly tied to increases in business risk were the increase in the allowed common equity ratio of Terasen Gas (TGI) from 35% to 40% in December 2009 and the increase in the allowed common equity ratio of Terasen Gas (Whistler) (TGW) in April 2009.

   With respect to TGI, in its December 2009 decision the British Columbia Utilities Commission cited the increase in long-term business risks arising from First Nations related risks and risks related to the potential impact of climate change policies. The former refers to increased operational and regulatory complexity due to the lack of certainty of the nature and extent of aboriginal rights and title in BC together with the lack of treaties. The latter refers to the probability that, due to provincial policy that favours reliance on green technologies (e.g., hydroelectricity), potential customers will opt for electricity over natural gas.

   TGI's earlier (2006) allowed increase in its common equity ratio (from 33% to 35%) was attributed to debt downgrades that the utility had experienced, to the elimination of preferred shares since its capital structure had previously been reviewed and to the capital structures of its Canadian peers. While the BCUC increased the common equity ratio of Terasen Gas (Vancouver Island) (TGVI) from 35% to 40% in 2006 at the same time it increased that of TGI, the Commission did not cite an increase in business risk, rather that it considered that its business risk was considerably higher than that of a low risk benchmark utility (e.g., TGI).

With respect to TGW, the BCUC raised its common equity ratio from 35% to 40% as a result of its finding that the business risks will have increased following the utility's conversion from a propane to a natural gas distribution system due to a doubling of its rate base but no change in its customer base, and due to the bonus/penalty condition of the utility's acceptance of its Certificate of Public Convenience and Necessity for the conversion (i.e., it would be subject to construction cost risks).

Subsequent to the BCUC's decision in 2009, raising TGI's common equity ratio from 35% to 40%, Pacific Northern Gas negotiated increases in the common equity ratios for its three separate divisions (from 36% to 40% for Fort St. John/Dawson Creek and from 40% to 45% for PNG-West).

With respect to ATCO Gas, there have been two increases in the allowed common equity ratio since 2000, the first as a result of the Generic Cost of Capital Decision in 2004 (equity ratio raised from 37% to 38%). In that decision, which determined the common equity ratios for eleven different regulated entities, the regulator considered various factors relevant to the capital structure, including business risk, the last awarded capital structure, interest coverage ratios, bond rating analysis and comparable awards by regulators in other jurisdictions. The Generic Cost of Capital Decision does not refer to an increase in business risk as a reason for the increase in ATCO Gas' common equity ratio.

In the 2009 Generic Cost of Capital Decision, the regulator determined, for each utility, the capital structure that, in its judgment, (1) would allow a stand-alone utility to maintain a credit rating in the A range subject to company-specific circumstances and (2) would recognize the need for the ongoing viability of the utility even in adverse conditions. With respect to the latter, the regulator decided to increase the common equity ratios across the sectors. AltaGas' equity ratio was increased by two percentage points as a result, not due to a finding of increased business risk. ATCO Gas' common equity ratio was increased by a lesser amount than the remainder of the Alberta utilities (by one percentage point, from 38% to 39%) based on the regulator's conclusion that ATCO Gas' business risk had declined due to the approval of a weather normalization deferral account.

The increase in the allowed common equity ratio for Union Gas from 35% to 36% was the result of a negotiated settlement. A review of the subsequent decision of the Ontario Energy Board which increased the allowed common equity ratio for Enbridge Gas Distribution (EGD) from 35% to 36% does not indicate that the allowed increase was due to a conclusion on the part of the regulator that EGD's business risk had increased, but rather a consideration that the capital structures of the two gas distributors should be comparable and EGD's need for additional financing flexibility.

ii. With respect to the removal of businesses such as water heater rentals from regulated operations, if the affected utility is (1) subject to weather risk and (2) its financing flexibility in terms of interest coverage ratios was already limited, that removal may warrant an increase in the common equity ratio. This is due to the fact that revenues from activities such as water heater rentals provide an offset to an earnings (and an interest coverage) decline resulting from warmer than normal weather. Ms. McShane is not aware of any other regulatory changes that would point to a need for an increase in the allowed common equity ratios. For a gas distribution utility that no longer needs to purchase and finance purchases of natural gas, all other things equal, a lower common equity ratio might be warranted. However, any such assessment needs to be made in light of all factors that are relevant to the appropriate common equity ratio, including but, not necessarily limited to, capital expenditure requirements, the impact of lower income tax rates on interest coverage, the impact of change in capital cost allowances on coverage ratios, and trends in the requirements of lenders as regards credit metrics.

2. With respect to equity market related risk measurements, a review of the trends in betas and standard deviations for the relatively few regulated companies that are publicly-traded does not indicate that there has been an upward trend in utility risk. However, these measurements are historical values which reflect the risks that have been experienced during the period over which they are measured, as contrasted with the risks that investors perceive as potential outcomes in the longer-term. Further, these measurements in principle reflect total risk, that is, both business and financial risk. To the extent that increased business risk has been offset by decreased financial risk, all other things equal, there would be no change in measurements of total risk. As regards the universe of Canadian utilities, a review of allowed and actual returns does not indicate a trend in the utilities' ability to earn the allowed ROE. There have been a number of debt downgrades since the end of 1999. Of the six operating companies which were rated by DBRS in both 1999 and 2010, and which are either gas distribution utilities (Enbridge Gas Distribution, Gaz Métro, PNG, Terasen Gas, and Union Gas) or have significant gas distribution utility operations (CU Inc.), three have ratings that are lower than at the end of 1999 (Enbridge Gas, PNG and CU Inc.). The DBRS ratings of the remaining three are the same. With respect to S&P, in late 2000, it acquired the Canadian Bond Rating Service (CBRS). Of the six companies identified above, four of the S&P ratings are lower than those previously assigned by CBRS, one is higher (Terasen Gas Inc.) and one (PNG) no longer has an S&P rating.

3. The requested decision is attached.

Public Intervenor
Interrogatory No. 22

Reference: Exhibit B – Cost of Debt

Interrogatory:

1. In her discussion of the cost of debt for EGNB, will Ms. McShane confirm that Enbridge Inc's cost of debt reflects the risks of investing in a variety of companies some of them expanding and some of them mature? Further, would Ms. McShane agree that a parent's cost of debt generally reflects the cost of financing new opportunities plus the roll-over of "old" debt into "new" debt? As such, would Ms. McShane agree that Enbridge Inc's debt already reflects the cost of financing entities like EGNB? If not why not?

2. Please provide a full list of all the entities that Enbridge Inc's debt issues currently finance.

3. Please confirm that Enbridge Gas Distribution Inc (EGDI Ontario) finances its operations through its own debt issues.

4. Please provide a table with the monthly debt cost of EGDI, Enbridge Inc, and Enbridge Pipelines since January 2000.

5. Please indicate any evidence that Ms. McShane is aware of that suggests that holding company debt costs are higher than those for operating subsidiaries that are properly ring fenced.

6. Please indicate how the treasury function of EGNB is managed, whether this is by EGNB staff or Enbridge Inc's staff, and whether this will change as EGNB moves into the mature stage

7. Ms. McShane indicates (Page 22 of her opinion) that "the cost of debt must be assessed in light of the covenants that are attached." Please indicate whether she means this statement to refer to non-arms length debt between a parent and a controlled subsidiary, as well as normal arms length debt. Does she see any difference between the two?

8. Ms. McShane discusses EGNB's possible stand-alone debt rating. Please confirm that a development stage entity like EGNB is not normally financed through the capital markets but by project finance? Please indicate whether Ms. McShane has looked at normal project financing benchmarks to assess EGNB rather than public debt market criteria. If not, please explain why she has not.

Response:

1. Enbridge Inc.'s cost of debt would reflect the risks of investing in a variety of companies, some mature and some new and/or expanding. Enbridge Inc.'s cost of debt would reflect risks of all of the underlying operations from which it derives an earnings stream, including those for which Enbridge Inc. raises debt directly and those which raise debt under their own name. While Enbridge Inc.'s cost of debt reflects the cost of financing EGNB, that does not mean Enbridge Inc.'s cost of debt is equal to that of EGNB. It reflects the combined (and diversified) risks of all of the underlying operations.

2. EGNB does not believe the entities that Enbridge Inc's debt issues currently finance is relevant to the determination of EGNB's cost of debt.

3. Confirmed.

4. The following table presents the September 2000 to May 2010 month end yields on three individual outstanding bonds, one each for Enbridge Inc., Enbridge Pipelines Inc., and Enbridge Gas Distribution Inc., as a proxy for each one's cost of long-term debt:

	Enbridge Inc.	Enbridge Pipelines Inc.	EGDI
Coupon	7.22	6.05	6.1
Maturity	07/24/30	02/12/29	05/19/28
Sep-00	7.12	7.03	6.98
Oct-00	7.21	7.08	7.06
Nov-00	7.14	6.97	6.99
Dec-00	7.25	6.92	7.00
Jan-01	7.24	7.02	7.05
Feb-01	7.10	6.92	6.97
Mar-01	7.24	7.04	7.09
Apr-01	7.30	7.27	7.27
May-01	7.41	7.30	7.25
Jun-01	7.38	7.16	7.15
Jul-01	7.24	7.03	7.06
Aug-01	7.08	6.85	6.88
Sep-01	7.46	7.13	7.18
Oct-01	7.29	6.89	7.09
Nov-01	7.09	6.89	6.89
Dec-01	7.53	7.18	7.18
Jan-02	7.30	6.95	7.10
Feb-02	7.48	7.13	7.18
Mar-02	7.56	7.36	7.23
Apr-02	7.42	7.20	7.07
May-02	7.34	7.07	7.02
Jun-02	7.20	6.95	6.90
Jul-02	7.37	7.14	7.14
Aug-02	7.15	6.95	6.90
Sep-02	6.92	7.37	6.87
Oct-02	7.02	7.42	6.97
Nov-02	7.26	6.94	6.89
Dec-02	7.04	6.67	6.62
Jan-03	7.16	6.76	6.71
Feb-03	7.20	6.74	6.80
Mar-03	7.48	6.98	6.93
Apr-03	7.14	6.77	6.72
May-03	6.76	6.31	6.31
Jun-03	6.74	6.29	6.34
Jul-03	7.02	6.62	6.60
Aug-03	6.85	6.58	6.56
Sep-03	6.57	6.24	6.14
Oct-03	6.79	6.46	6.41
Nov-03	6.27	6.07	6.07
Dec-03	6.35	6.05	6.04
Jan-04	6.27	6.07	6.07
Feb-04	6.12	5.95	5.92
Mar-04	6.14	5.94	5.89
Apr-04	6.43	6.23	6.23
May-04	6.45	6.22	6.26
Jun-04	6.70	6.40	6.46
Jul-04	6.53	6.28	6.35
Aug-04	6.37	6.17	6.17
Sep-04	6.35	6.13	6.09
Oct-04	6.30	5.98	5.96
Nov-04	6.28	5.99	5.98
Dec-04	6.09	5.83	5.74
Jan-05	5.98	5.72	5.69
Feb-05	5.98	5.75	5.73
Mar-05	6.00	5.72	5.72
Apr-05	5.91	5.61	5.61
May-05	5.69	5.39	5.37
Jun-05	5.48	5.23	5.18
Jul-05	5.45	5.21	5.21

	Enbridge Inc.	Enbridge Pipelines Inc.	EGDI
Coupon	7.22	6.05	6.1
Maturity	07/24/30	02/12/29	05/19/28
Aug-05	5.29	5.01	5.02
Sep-05	5.42	5.11	5.12
Oct-05	5.60	5.26	5.29
Nov-05	5.46	5.15	5.17
Dec-05	5.34	5.01	5.03
Jan-06	5.53	5.20	5.22
Feb-06	5.52	5.12	5.21
Mar-06	5.64	5.23	5.32
Apr-06	5.86	5.49	5.54
May-06	5.86	5.46	5.51
Jun-06	6.10	5.58	5.65
Jul-06	5.86	5.34	5.40
Aug-06	5.67	5.14	5.21
Sep-06	5.57	5.04	5.08
Oct-06	5.52	5.02	5.03
Nov-06	5.42	4.92	4.93
Dec-06	5.67	5.07	5.10
Jan-07	5.75	5.15	5.19
Feb-07	5.58	5.03	5.06
Mar-07	5.75	5.15	5.16
Apr-07	5.97	5.13	5.21
May-07	6.07	5.37	5.42
Jun-07	6.24	5.54	5.53
Jul-07	6.25	5.56	5.55
Aug-07	6.23	5.58	5.58
Sep-07	6.42	5.61	5.61
Oct-07	6.25	5.50	5.53
Nov-07	6.28	5.38	5.37
Dec-07	6.18	5.33	5.32
Jan-08	6.25	5.50	5.49
Feb-08	6.25	5.45	5.42
Mar-08	6.25	5.35	5.38
Apr-08	6.59	5.69	5.72
May-08	6.60	5.65	5.65
Jun-08	6.61	5.71	5.74
Jul-08	6.63	5.73	5.76
Aug-08	6.79	5.94	5.96
Sep-08	7.28	6.18	6.25
Oct-08	8.98	7.38	7.42
Nov-08	8.52	7.02	6.96
Dec-08	8.28	6.53	6.65
Jan-09	8.32	6.87	7.01
Feb-09	8.11	6.81	6.74
Mar-09	7.74	6.49	6.37
Apr-09	7.32	6.57	6.29
May-09	6.89	6.24	5.96
Jun-09	6.33	5.63	5.62
Jul-09	6.00	5.26	5.56
Aug-09	5.74	5.35	5.40
Sep-09	5.64	5.30	5.39
Oct-09	5.78	5.38	5.43
Nov-09	5.69	5.25	5.28
Dec-09	5.92	5.48	5.56
Jan-10	5.75	5.33	5.32
Feb-10	5.72	5.38	5.36
Mar-10	5.64	5.41	5.29
Apr-10	5.61	5.35	5.23
May-10	5.68	5.36	5.28

Source: RBC Capital Markets

5. Ms. McShane is aware of the rating approaches of the debt rating agencies as regards holding companies versus their operating subsidiaries and how the ratings may differ between the two. Differences in the ratings as between the holding companies and their operating subsidiaries depend on the specific circumstances. If the holding company issues debt and that debt is structurally subordinate (ranks below in terms of claims on the assets) to the debt that is issued by ring-fenced operating companies, the rating of the parent company may be lower, and the cost of debt higher, than the blended rating of the ring-fenced subsidiaries.

6. The Treasury function of EGNB is currently managed by Enbridge Inc. staff. EGNB does not expect this to change as it moves into the mature stage as the function can be provided more cost effectively by Enbridge Inc.

7. The statement was intended to provide a context for an assessment of the reasonableness of the cost of debt that might be incurred by a controlled subsidiary like EGNB by reference to costs of debt incurred in an arms' length transaction. The cost of debt incurred in an arms' length transaction is a function of the underlying strength of the operations as well as the nature of the covenants of the debt and the protections that they provide to the debtholders. To illustrate, suppose a firm issues two 10-year debt issues, one a first mortgage bond, and amortized over ten years, the other requiring only interest payments until maturity, subordinated to the first mortgage bond. The cost of the first would be lower than the latter, because of the greater protection to the debt holder, even though the identity of the borrower is the same. As Enbridge Inc. does not impose any restrictive covenants when lending funds to EGNB, the cost of debt that is allowed to be charged to EGNB should be evaluated in that context.

8. While Ms. McShane agrees that a firm in the development stage like EGNB would not be able to access the conventional public debt markets, she did not look at project financing benchmarks, as she did not view project financing as relevant to EGNB. Infrastructure project financing typically entails the financing of discrete assets (e.g., a pipeline or independent power project) with a relatively stable stream of cash flows, often backed by contracts, and debt covenants, including liens on the assets of the project, and annual retirement of the project financed debt. Project financed debt may entail a minimum debt service coverage ratio (DSCR), which measures the cash flow available to service debt. The level of the DSCR that might be required by lenders is a function of the stability of the stream of cash flows and the other debt covenants imposed to protect the debt holders (of which there are none in EGNB's case, as indicated in response to 7. above).

Public Intervenor
Interrogatory No. 23

Reference: Exhibit B – Long Canada Yields

Interrogatory:

1. Ms. McShane discusses trends in the cost of capital on pages 25-27.

    i. Please provide a copy of the Consensus Economics forecast by which she derives a 4.8% average long term Canada yield over the next five years.

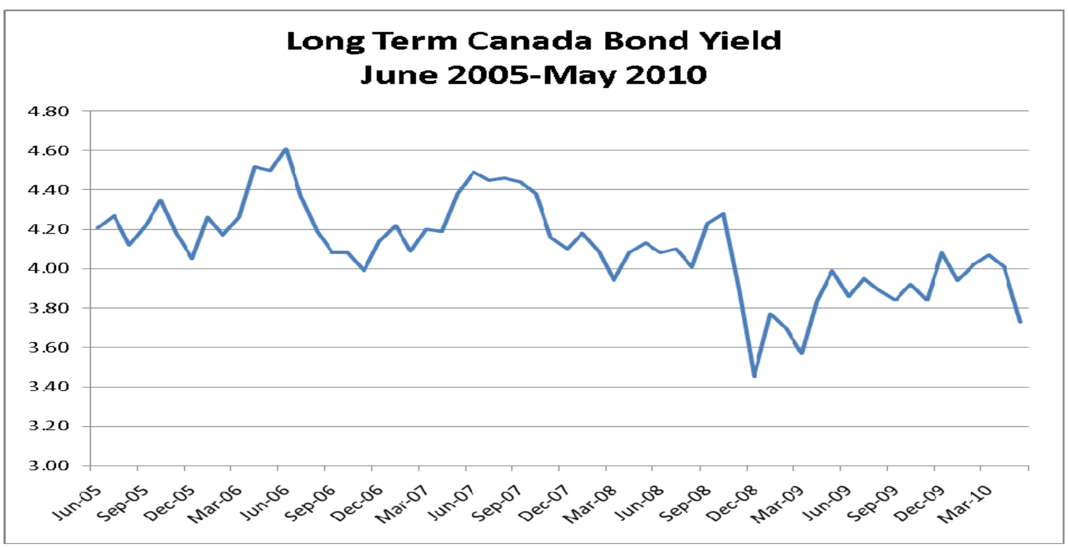
    ii. Please provide a graph of the monthly yield of the long Canada bond yield over the last five years.

2. Ms. McShane concludes that the cost of capital has declined since 1999. Please provide an estimate of the extent to which the overall cost of capital has declined.

Response:

1.
    i. Please see response to Board Interrogatory No. 8. Please note that the 4.8% estimate refers to the forecast yield on 10-year Canada bonds, not the yield on long-term (30-year) Canada bonds.

    ii. The requested graph of the monthly long Canada bond yield over the last five years is provided below.



2. The term "cost of capital" used in the referenced statement encompasses a broad range of securities, including government bonds of various terms, corporate bonds and equities.

There is no single measure of the decline in the cost of capital as securities are impacted differently by changes in the capital markets and the economy.

The extent of the decline in the cost of utility equity capital is analyzed in Exhibit B, Sections IX and X. Based on that analysis, the cost of utility equity is estimated to have declined by approximately 0.50% to 1.0% since 1999.

Public Intervenor
<u>Interrogatory No. 24</u>

Reference: Exhibit B – Benchmark Utilities

Interrogatory:

1. Ms. McShane discusses conceptual issues in estimating the fair return on pages 36-37. Can Ms. McShane confirm that:

   i. It is better to have one accurate estimate than three estimates of which only one is accurate. If not, why not?

   ii. Can Ms. McShane confirm that, as a limited partnership, Gaz Metro is exposed to risks that a regular corporation is not, such as changes in tax treatment as referenced in Footnote 27? As such, could Gaz Metros' risk assessment over-state the risks of a benchmark utility? If not, why not?

   iii. Please confirm that Ms. McShane assumes not just that US utilities are comparable, but that they are identical, since she makes no adjustment to the estimates from US utilities as applied to a Canadian benchmark.

   iv. Please provide all analyses performed by Ms, McShane to indicate that the market risk premium, base interest rates, monetary policy, tax treatment and other institutional features are identical between the US and Canada as is required to take opportunity costs from one country to apply to another without adjustment.

   v. Please indicate what Ms. McShane understands by interest rate parity (IRP) and explain, by means of an example, how it equilibrates interest rates between two different countries operating with different currencies like the US and Canada.

2. For the US utilities in Schedule 6 which Ms. McShane assumes are identical to a Canadian benchmark, please provide their recent 10Ks, plus an assessment of their regulatory regime and any other facts required to meaningfully assess their risk.

Response:

1.

   i. In the abstract, if a single test produced an accurate estimate of the fair return then there would be no need for additional tests. However, please see lines 903 to 931 of Ms. McShane's evidence.

   ii. Ms. McShane does not understand what risk assessment of Gaz Métro the question is referring to. Ms. McShane has not relied on Gaz Métro in her sample of benchmark utilities.

iii. Ms. McShane does not assume that the U.S. utilities are identical to a benchmark Canadian utility. No individual utility is identical to another. The companies in the benchmark utility sample are not identical to each other. If it were a precondition that a proxy company be identical to the subject company in order to use it for the purpose of making cost of equity assessments, it would be virtually impossible to undertake any meaningful cost of equity estimates. Ms. McShane confirms that she did not make any adjustments to the DCF results.

iv. Ms. McShane has not performed any formal analyses. She regularly compares various indicators of the cost of capital in the U.S. and Canada to assess whether it is reasonable to rely upon estimates of the cost of equity for U.S. utilities in estimating the cost of equity for a benchmark Canadian utility. For example, to date during June (through June 22), the 10-year Canada bond yield has been approximately 10 basis points higher than the 10-year U.S. Treasury bond yield, while the 30-year Treasury bond yield has been approximately 0.4 % higher than in Canada. The average yield on the 20-year and 30-year U.S. Treasury inflation-indexed bonds has been approximately 0.25% higher than the yield on the benchmark long-term government of Canada inflation-indexed bond. The indicated break-even inflation rates (measured as the difference between the yield on the nominal and inflation-indexed bonds) in the two countries are within 10 basis points of each other. The most recent Consensus Economics, *Consensus Forecasts*' long-term outlook (April 2010) for 10-year yields anticipates that the U.S. 10-year yield over the next 10 years will be 0.3% higher than in Canada. The end of May 2010 yield on the Moody's long-term AAA and AA corporate bonds in the U.S. were 5.01% and 5.28% respectively; the Canadian DEX AAA/AA long-term corporate bond index yield was 5.29%. The long-term Moody's and Canadian DEX BBB bond index yields were 6.2% and 6.05% respectively.

With respect to monetary policy, the approaches are different. The explicit goal of the Bank of Canada's monetary policy is to maintain inflation within a target range of 1% to 3%, while the Federal Reserve has as its twin objectives the promotion of maximum sustainable output and the maintenance of stable prices, i.e., low inflation. Although the Federal Reserve has no explicit inflation target, inflation is expected to be similar in the two countries, as is real economic growth. The consensus forecast of inflation as published by Consensus Economics in April 2010 is for consumer Price inflation to average 2% in Canada and 2.2% in the U.S. over the next 10 years (2011-2020), with real GDP growth averaging 2.6% in Canada versus 2.8% in the U.S.

With respect to the tax regime, while the tax treatment of dividends and interest has differed in the two countries (Canada has had a dividend tax credit for many years; the U.S. lowered dividend tax rates in mid 2003 and is expected to raise them in 2011), the marginal investor in both countries is likely to be non-taxable (e.g., a pension fund or an RRSP/IRA or 401-K). On average, over half the shares in the companies in the benchmark U.S. utility sample are held by institutions. In this context, the average benchmark sample dividend yield/long-term Treasury bond yield for the period 1995-

May 2003 (pre-dividend tax cut) was virtually identical to the average ratio from June 2003 to September 2008 (prior to the equity market crash). If the dividend tax cut had had a significant impact on investors' required returns, there should have been a material decline in the dividend/bond yield ratio after the tax cut.

With respect to the market risk premium, while the historic risk premium has been higher in the U.S., the difference has been due to higher interest rates in Canada, which is no longer the case. As indicated on Schedules 14 and 15 of Ms. McShane's evidence, the nominal rates of return on the equity composites over both periods shown have been similar in the two countries. A 2007 study by the Bank of Canada found that since government bond yields have converged in the two countries, the difference in the cost of equity financing between the two countries is statistically insignificant (Lorie Zorn, *Estimating the Cost of Equity for Canadian and U.S. Firms*, Bank of Canada, Autumn 2007).

While the comparability of the cost of capital environment in the two countries will need to be reassessed on an ongoing basis given the higher government deficit in the U.S. versus Canada, at present, the cost of capital indicators continue to be sufficiently similar for the purpose of relying on the cost of equity for a sample of low risk U.S. utilities as proxies for a benchmark Canadian utility.

v. Interest rate parity means that the difference in interest rates between two countries operating in two different currencies is equal to the difference between the spot and forward exchange rates, as per the following formula.

$$F/E = (1 + I_{US}) / (1+I_C)$$

Where

F = Forward Exchange Rate (US$/Cdn$)
S = Spot Exchange Rate (US$/Cdn$)
I_{US} = Nominal Interest Rate, US
I_C = Nominal Interest Rate, Canada

If the one year interest rate in Canada is 2% and the one year interest rate in the U.S. is 2.5% and the spot exchange rate is $1.02 U.S/$1.00 Canada, then if interest parity holds, the one year forward exchange rate should be $1.03 U.S./Canada.

$$F/1.02 = (1 + 2\%) / (1 + 2.5\%)$$

Solving for the forward exchange rate (F):

$$1.03 = [(1+2\%)/(1+2.5\%)]*1.02$$

2. Schedule 6 presents the financial metrics for the "typical mature U.S. gas distribution utility". Please see Exhibit B page 20 lines 511-513. They were not intended to be representative of a Canadian benchmark utility and were not presented as such.

The requested 10-ks for these companies are large documents that are publicly available at http://www.sec.gov/edgar/searchedgar/companysearch.html. As a result, EGNB has not provided copies with this response

Ms. McShane's benchmark sample is comprised of the nine utilities in Schedule 7. These utilities were selected for use as a proxy sample; no proxy is identical to the company(s) that it is selected to represent. The 10-ks for this group of companies are also available at http://www.sec.gov/edgar/searchedgar/companysearch.html.

A summary of information on the deferral accounts and incentive mechanisms permitted for the companies in the sample as well as information on the latest regulatory decision for the utility is attached.

Public Intervenor
Interrogatory No. 25

Reference: Exhibit B – Regulatory Decisions

Interrogatory:

1. Ms. McShane discusses recent Canadian regulatory decisions on Page 28-33. However, there is very little discussion of the reasons for the revisions of the allowed ROEs for 2010 and 2011. Please indicate why there is no significant discussion of these reasons. In particular:

   i) Would Ms. McShane agree that practically every decision discusses the change in corporate bond yields during the financial crisis of 2008/9?

   ii) Would Ms. McShane agree that several decisions specifically awarded a bonus to the ROE for the extraordinary events of 2008/9? If not, why not?

   iii) Would Ms. McShane agree that the bond market is largely back to normal given where we are in the business cycle? If not, why not? Explain in detail?

   iv) Does Ms. McShane judge the extraordinary events of 2008/9, which motivated the higher allowed ROEs in 2009/10, to be reflective of capital markets going forward, and, as such, are they a good basis of a fixed ROE for EGNB? Please discuss in detail.

2. With reference to Footnote 20, can Ms. McShane agree that, contrary to the OEB statement there, Dr. Booth did not enter written ROE testimony during the OEB's technical conference? Instead, he simply answered the questions on the OEB's issues list, and that the reference to "overwhelming" comes from a survey of US CFOs, which indicated that they overwhelmingly used the CAPM, rather than from Dr. Booth's own estimates. If not, why not?

3. On Page 32, Ms. McShane justifies a 0.50% drop in EGNB's allowed ROE by taking the difference between its 1999 allowed ROE and the 2009 allowed ROEs for the sample of Canadian utilities. Please confirm that for EGNB, the question of the allowed ROE is for a future ten-year period and not one based on the 2009 ROE decisions made during the middle of the worst financial crisis since 1937. If not, why not?

4. With respect to the allowed ROEs of US utilities, please indicate any Canadian board decisions that have directly used US estimates in deriving a fair ROE for a Canadian utility without making any adjustments.

Response:

1. The objective of the references to the most recent allowed ROEs for mature Canadian gas distributors and those allowed for U.S. gas distribution utilities was to provide a similar

approach to that taken in NBPUB 299 for the assessment of the reasonableness of the 13% ROE which had been requested by EGNB. While that comparison provides a perspective on the trend in allowed returns, Ms. McShane's report also includes a detailed "from first principles" estimate of the fair return for EGNB.

Ms. McShane agrees that each of the four decisions which underlie Table 4 discussed trends in corporate bond yields. She also agrees that spreads have declined materially since their financial crisis peaks and are close to normal for the relevant phase of the business cycle (recovery from recession), i.e., higher than their long-term average. The long-term A rated corporate bond yield spread over the long-term Canada bond averaged approximately 1.0% between the beginning of 1990 and the end of 2007 (before the onset of the financial crisis). It was 1.5% at the end of April 2010. While the markets are close to normal for the stage of the business cycle, they remain vulnerable, as illustrated by a widening of spreads in May 2010. As investor concerns with the financial crisis in Europe spilled over into North American markets, long-term Canada bond yields declined, while corporate bond yields remained flat, increasing the long-term A rated corporate bond yield spread to 1.8%.

Of the four decisions which underlie Table 4, two of them (the Alberta Utilities Commission's Generic Cost of Capital Decision and the Régie's decision for Gaz Métro) incorporated an adjustment for financial market conditions. However, there is no basis for concluding that the average allowed ROE of 9.5% shown on that table is not a relevant benchmark, as discussed further below.

ATCO Gas:

In its November 2009 decision, the Alberta Utilities Commission set an allowed ROE of 9.0% for each of 2009 and 2010, and on an interim basis for 2011, with an underlying long-term Canada bond yield of approximately 4.3%. In its Decision, the AUC stated that "the traditional spread between the long Canada bond yield and the yield on high grade bonds had increased to well above the traditional spread of one percent and by the close of the record in the proceeding had moved back to a spread of approximately 1.5 percent. As a result, the Commission concludes that the CAPM results likely underestimate the required market equity return by at least 50 basis points." The 9.0% ROE adopted by the AUC was approximately 0.45% above the level that would have been indicated by the formula at a long-term Canada bond yield of 4.3%. As indicated above, high grade corporate bond yield spreads are still higher than their long-term average, by approximately the same amount as the AUC cited in its decision. Further, if the formula were applied at the forecast long-term Canada bond yield of 5.0% relied upon in Ms. McShane's report, the indicated ROE would be 9.1%, slightly higher than the 9.0% adopted for 2009 and 2010.

Enbridge Gas and Union Gas:

While the Ontario Energy Board's consultation on the cost of capital was clearly convened as a result of the financial crisis, the outcome indicates that the Board had some fundamental concerns with the benchmark return and formula. There is no indication that the ROEs which result from the OEB's cost of capital policy report contain an increment for the financial crisis. The resulting ROEs in Table 4 (which were based the application of the new formula to a forecast long-term Canada bond yield of 4.5%) are an appropriate baseline for comparing current levels of allowed ROEs to those prevailing in NBPUB 299.

Gaz Métro:

The Régie's ROE of 9.20% for Gaz Métro for 2010, which was based on a long-term Canada bond yield of 4.3%, incorporates a premium of 0.25% to 0.55% for the effect of the financial crisis. The Régie renewed its automatic adjustment formula for 2011; the 9.20% ROE for 2010 will be adjusted for 75% of the change in forecast long-term Canada bond yields to arrive at the 2011 ROE. There is no indication in the decision that, for 2012, the Régie will automatically revert to the base ROE which it had relied on prior to the 2009 decision. In any event, were the Régie to remove the approximately 0.4% financial crisis premium effective in 2012, the application of the formula to a forecast long-term Canada bond yield of 5.0% would result in an ROE of 9.325%, higher than the ROE adopted for 2010 at a long-term Canada bond yield of 4.3%.

Terasen Gas:

There is no indication in the BCUC's decision for Terasen Gas, allowing a 9.50% ROE for 2010 (and eliminating the formula), that there was any premium added for the financial crisis. In that decision, the BCUC directed Terasen Gas to file its study of alternative formulae by the end of 2010, but did not direct Terasen Gas to revisit the ROE established for 2010. Hence, it is reasonable to conclude that the 9.50% ROE established for 2010 would be the starting ROE should the BCUC decide to reinstate a formula. Since Terasen Gas has not yet filed the study requested by the BCUC, there is no basis for concluding that there would be any change from the 9.5% ROE set for 2010, although it bears noting that the long-term Canada bond yield underpinning the BCUC's 9.50% ROE was 4.3%, lower than the 5.0% forecast relied on by Ms. McShane for the purpose of estimating a fair ROE for EGNB "from first principles."

2. The referenced footnote number in the question is incorrect. The correct footnote is #21. Ms. McShane agrees that the submissions made to the Ontario Energy Board in EB-2009-0084 were not sworn testimony. It is clear from the referenced quote presented in the footnote that the OEB was referencing Dr. Booth's written submission, as the Board stated "in his written comments, Dr. Booth recommended…." The quote utilized by the Board in its Report is taken from Dr. Booth's September 2009 written submission (September 2009) The reference to "overwhelming" does not appear to be to a survey of CFOs, but to the statement at page 20, lines 14-15 of Dr. Booth's submission which clearly states: "I would therefore recommend that the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate."

3. It is confirmed that the ROE for EGNB is to be determined for a future period; to Ms. McShane's knowledge, there is no predetermined period over which the ROE adopted will apply. Please also see response to part 1 above.

4. Ms. McShane is not aware of any Canadian board decision directly using US estimates without corroborating Canadian data.

Public Intervenor
Interrogatory No. 26

Reference: Exhibit B – US Utility Comparables

Interrogatory:

1. On Page 38, Ms. McShane discusses her DCF estimates based on US utilities:

   i. Please indicate why, as compared to other 2010 testimony, she no longer provides a direct constant growth model estimate based on IBES analyst forecasts, and why she has now substituted a sustainable growth estimate. Is it her judgment that the relative value of these two models has changed in the last six months? If so, please explain in detail what factors motivated the change.

   ii. Please indicate all testimony, since 2000, where Ms. McShane has used a sustainable growth model to estimate a DCF cost of capital and the advantages of this model.

2. In Schedule 9, Ms. McShane indicates that the average forecast growth rate for her US utilities is 5.29%. Please confirm that this is an infinite growth rate and that it exceeds the forecast growth rate for the US economy, which she places at 5.0% in Schedule 10. Please confirm that, if her estimates are correct, eventually the entire US economy will consist of utilities, since they are forecast to grow more rapidly forever than the US economy.

3. With her three stage growth model, Ms. McShane assumes that these utilities will grow at the average growth rate of US GDP of 5.0%. Please provide all statistical work that supports this assumption. In particular, please provide the earnings per share, book value per share, dividend per share, and net rate base per share for each of the utilities in her US proxy sample back to 1990, and the annual growth rate in each. Then, please estimate a regression of the annual growth rate in each of these variables against the annual growth rate of US GDP and report the size of the coefficients and the significance of the estimates.

4. Please indicate whether, in Ms. McShane's judgment, which of the sustainable growth, constant growth (with IBES forecasts), or three-stage model is a more reliable model of a utility's fair ROE.

Response:

1.

   i. As discussed in Exhibit B, page 38, lines 967 to 969, in estimating the constant growth model "I relied on two different estimates of the growth component of the model: investment analysts' long-term (five-year) earnings growth rate estimates and the sustainable earnings growth rate." The use of I/B/E/S analyst growth forecasts in estimating the constant growth DCF model is discussed in Appendix B on page B-4. The results of the analysis are presented in Schedule 8.

ii. Ms. McShane has not maintained a complete list of all testimonies since 2000 where she used a sustainable growth model, but some examples in Canada include testimony filed on behalf of ATCO Pipelines (January 2003), ATCO Utilities/AltaGas (July 2003), Centra Gas BC (July 2002), Enbridge Gas Distribution (September 2002), Gazifère (February 2010), Natural Resource Gas (March 2010), Newfoundland and Labrador Hydro (April 2003), Newfoundland Power (October 2002), and Union Gas (June 2001). Ms. McShane does not view one method as superior to the other; they are simply alternative ways of estimating the same thing, the long-term growth in earnings expected by investors.

2. It is confirmed that the forecast growth rate exceeds the current forecast nominal growth rate for the U.S. economy. Growth in earnings/corporate profits cannot exceed, in the longer term, growth in the economy as a whole, as corporate profits would overwhelm the GDP. However, the fact that the growth rates for this sample exceed the forecast growth rate in the economy does not mean that the entire U.S. economy will be dominated by utilities, as the growth forecasts are specific to this sample (and relate to the dividend yields of the sample) and because not all companies in the economy will grow in the longer-term at the rate of growth in the economy.

3. The growth component of a DCF model is intended to be an estimate of what investors expect the long-term growth to be and thus build into the prices they are willing to pay (and thus is embedded in the dividend yield component of the model). Ms. McShane's use of forecast long-term growth in the economy as a reasonable estimate of investors' expectations for long-term growth in earnings for mature industries is based on the link between corporate profits and GDP growth in the long-term. The two primary determinants of profit growth are growth in nominal GDP and unit labour costs. Nominal GDP measures the current dollar value of the goods and services produced in the economy. Simplistically, GDP less payments to labour, depreciation, plus income from abroad equals corporate profits. As long as labour costs are contained, increases in economic growth will be reflected in growth in profits. To Ms. McShane's knowledge, the conclusion that corporate profit growth will track GDP growth in the long-term is not contested.

   However, industries and companies go through life cycles. During the different phases of the cycle, growth would reasonably be expected to differ from the long-term average. The phases of the life cycle include introduction (or initial growth), rapid growth, maturity and decline. In the first two phases, industry growth would be expected to outpace growth in the economy as a whole, and then in maturity stabilize at a level similar to that of the general economy. Decline is characterized by falling demand for the industry's products and/or services. As noted at page B-5 (Appendix B), utilities are considered to be a quintessential mature industry.

   Ms. McShane notes that the FERC adopted direct reliance on expected long-term growth in GDP as an input to its DCF model for gas pipelines. In Order 396-B (Northwest Pipeline Corp., June 11, 1997), the FERC cited the fact that all experts in the proceeding had relied on long-term GDP forecasts as support for, or confirmation of, their pipeline growth forecasts in their own DCF models. The development of their model was in part validated by the valuation practices of Merrill Lynch and Prudential Securities who relied on the growth in the economy as their estimate of long-term growth for all firms, including regulated firms.

The following tables provide the requested information regarding earnings per share, book value per share and dividend per share for the utilities in her US proxy sample back to 1990.

Earnings Per Share Bef. Extraordinary 12 month moving average										
Year	AGL	ED	NJR	GAS	NWN	NST	PNY	SJI	WGL	Avg. EPS
1990	1.01	2.34	0.43	1.93	1.62	0.80	0.61	0.67	1.26	1.18
1991	1.04	2.32	0.37	1.86	0.67	0.98	0.44	0.64	1.14	1.05
1992	1.13	2.46	0.69	1.67	0.74	1.05	0.70	0.80	1.27	1.17
1993	1.08	2.66	0.73	1.97	1.74	1.14	0.73	0.78	1.31	1.35
1994	1.17	2.98	0.83	2.07	1.63	1.21	0.68	0.61	1.42	1.40
1995	0.50	2.93	0.86	1.96	1.61	1.04	0.73	0.70	1.45	1.31
1996	1.37	2.93	0.92	2.42	1.97	1.31	0.84	0.85	1.85	1.61
1997	1.37	2.95	0.99	2.62	1.78	1.36	0.91	0.86	1.85	1.63
1998	1.41	3.04	1.04	2.43	1.01	1.38	0.99	0.63	1.54	1.50
1999	1.30	3.14	1.12	2.63	1.70	1.39	0.94	1.01	1.47	1.63
2000	1.29	2.75	1.20	1.01	1.80	1.60	1.02	1.09	1.79	1.50
2001	1.63	3.22	1.35	2.70	1.90	-0.03	1.02	1.15	1.75	1.63
2002	1.84	3.14	1.41	2.90	1.63	1.53	0.95	1.22	0.81	1.71
2003	2.15	2.37	1.61	2.49	1.77	1.71	1.12	1.38	2.31	1.88
2004	2.30	2.33	1.73	1.71	1.87	1.78	1.28	1.57	1.99	1.84
2005	2.50	3.00	1.85	3.08	2.11	1.84	1.32	1.72	2.18	2.18
2006	2.73	2.97	1.88	2.88	2.30	1.94	1.28	2.48	1.94	2.27
2007	2.74	3.48	1.56	2.99	2.78	2.07	1.41	2.13	2.19	2.37
2008	2.85	3.37	2.61	2.64	2.63	2.22	1.50	2.60	2.35	2.53
2009	2.89	3.16	0.65	2.99	2.83	2.28	1.68	1.97	2.40	2.32

Book Value Per Share

Year	AGL	ED	NJR	GAS	NWN	NST	PNY	SJI	WGL	Avg. BKVLPS
1990	8.94	19.72	5.90	11.69	12.65	9.22	4.58	6.79	10.17	9.96
1991	9.40	20.17	5.71	12.30	12.27	8.94	4.83	6.77	10.34	10.08
1992	9.69	20.89	6.29	12.75	12.44	9.39	5.13	6.95	10.67	10.47
1993	9.89	21.63	6.09	13.04	13.08	9.69	5.45	7.17	11.04	10.79
1994	10.19	22.62	6.43	13.25	13.63	10.03	5.68	7.23	11.51	11.18
1995	10.14	23.51	6.47	13.67	14.55	10.29	6.16	7.34	11.95	11.56
1996	10.56	24.37	6.73	14.74	15.38	10.66	6.53	8.03	12.79	12.20
1997	10.99	25.18	6.92	15.43	16.02	11.04	6.95	8.05	13.48	12.67
1998	11.42	25.88	7.26	15.97	16.59	11.15	7.45	7.85	13.86	13.05
1999	11.59	25.31	7.57	16.80	17.12	13.29	7.86	8.30	14.72	13.62
2000	11.50	25.81	8.29	15.56	17.93	12.66	8.26	8.77	15.31	13.79
2001	12.19	26.71	8.80	15.86	18.56	11.90	8.63	9.29	16.24	14.24
2002	12.52	27.60	8.95	16.55	18.88	12.25	8.91	9.74	15.78	14.58
2003	14.66	28.37	10.26	17.13	19.52	12.84	9.36	11.26	16.83	15.58
2004	18.06	29.02	11.25	16.99	20.64	13.52	11.15	12.41	17.54	16.73
2005	19.27	29.74	10.60	18.36	21.28	14.37	11.53	13.50	18.36	17.45
2006	20.71	31.03	15.00	19.43	21.97	14.82	11.70	15.11	18.86	18.74
2007	21.74	33.31	15.50	20.94	22.52	15.95	11.84	16.25	19.89	19.77
2008	21.48	35.37	17.29	21.53	23.71	16.74	12.11	17.33	20.99	20.73
2009	22.97	36.40	16.59	22.94	24.88	17.53	12.67	18.24	21.89	21.57

Dividends per Share										
Year	AGL	ED	NJR	GAS	NWN	NST	PNY	SJI	WGL	Avg. DPS
1990	0.99	1.82	1.31	0.65	1.10	0.76	0.42	0.70	1.01	0.97
1991	1.02	1.86	1.12	0.67	1.13	0.79	0.44	0.70	1.04	0.98
1992	1.04	1.90	1.18	0.68	1.15	0.82	0.46	0.70	1.07	1.00
1993	1.04	1.94	1.22	0.68	1.17	0.85	0.49	0.72	1.09	1.02
1994	1.04	2.00	1.26	0.68	1.17	0.88	0.52	0.72	1.11	1.04
1995	1.05	2.04	1.28	0.68	1.18	0.91	0.55	0.72	1.12	1.06
1996	1.07	2.08	1.32	0.70	1.20	0.94	0.58	0.72	1.14	1.08
1997	1.08	2.10	1.40	0.72	1.21	0.94	0.61	0.72	1.17	1.10
1998	1.08	2.12	1.48	0.73	1.22	0.94	0.65	0.72	1.20	1.13
1999	1.08	2.14	1.56	0.75	1.23	0.97	0.69	0.72	1.22	1.15
2000	1.08	2.18	1.66	0.77	1.24	1.00	0.73	0.73	1.24	1.18
2001	1.08	2.20	1.76	0.79	1.25	1.03	0.77	0.74	1.26	1.21
2002	1.08	2.22	1.84	0.81	1.26	1.06	0.80	0.76	1.27	1.23
2003	1.11	2.24	1.86	0.84	1.27	1.08	0.83	0.78	1.28	1.25
2004	1.15	2.26	1.86	0.88	1.30	1.11	0.86	0.82	1.30	1.28
2005	1.30	2.28	1.86	0.92	1.32	1.16	0.92	0.86	1.32	1.33
2006	1.48	2.30	1.86	0.97	1.39	1.21	0.96	0.92	1.35	1.38
2007	1.64	2.32	1.86	1.03	1.44	1.30	1.00	1.01	1.37	1.44
2008	1.68	2.34	1.86	1.15	1.52	1.40	1.04	1.11	1.41	1.50
2009	1.72	2.36	1.86	1.27	1.60	1.50	1.08	1.22	1.46	1.56

Ms. McShane does not have the requested data on net rate base per share.

The analysis of historical growth rates in earnings per share, book value per share and dividends per share (as shown below) does not find them to be significantly correlated with GDP growth.

Growth Rate

Year	GDP	BKVLPS	DPS	EPS
1991	3.3%	1.2%	0.2%	-11.4%
1992	5.8%	3.8%	2.4%	11.2%
1993	5.1%	3.0%	2.3%	15.4%
1994	6.3%	3.6%	2.0%	3.7%
1995	4.7%	3.5%	1.6%	-6.4%
1996	5.7%	5.5%	2.3%	22.7%
1997	6.3%	3.9%	2.1%	1.6%
1998	5.5%	2.9%	1.9%	-8.2%
1999	6.4%	4.4%	2.1%	9.0%
2000	6.4%	1.2%	2.7%	-7.8%
2001	3.4%	3.3%	2.2%	8.4%
2002	3.5%	2.4%	2.1%	5.1%
2003	4.7%	6.9%	1.7%	9.5%
2004	6.5%	7.4%	2.3%	-2.0%
2005	6.5%	4.3%	3.6%	18.4%
2006	6.0%	7.4%	4.1%	4.1%
2007	5.1%	5.5%	4.1%	4.7%
2008	2.6%	4.8%	4.2%	6.7%
2009	-1.3%	4.0%	4.2%	-8.4%
Slope (Beta)		16.7%	-12.2%	155.4%
RSq		3.3%	4.9%	9.8%

Over the period 1990-2009, growth in earnings was approximately 4.0%; that of book value per share approximately 4.2%; and dividends approximately 2.5%. The lower growth rates relative to growth in GDP are consistent with a period characterized with generally declining interest rates and declining allowed returns. Allowed returns in the U.S. declined from approximately 12.7% in 1990 to approximately 10.4% in 2009 (Schedule 2, page 3 of 3). Such reductions are not compatible with earnings (and therefore dividends and book value per share) keeping pace with long-term economic growth.

4. The use of multiple models is intended to capture the range of expectations that is likely to be embedded in the prices of utility stocks, as it is impossible to know precisely what is in the minds of investors. Ms. McShane is of the view that all three models provide a reasonable perspective on the rates of growth that investors are likely to anticipate when pricing utility shares.

Public Intervenor
Interrogatory No. 27

Reference: Exhibit B – Risk Premium

Interrogatory:

1. In her discussion of the market risk premium on Page 43, Ms. McShane estimates the historic Canadian market risk premium at 1.1%-1.5% less than that in the US. How much of this difference would Ms. McShane ascribe to the following factors:

   i. The tax preferences for Canadians to hold equities, that is, the foreign property restriction and the dividend tax credit?

   ii. The role of the US $ as the world's reserve currency and, hence, lower returns on the US long treasury bond?

   iii. The higher returns earned on US securities in terms of the well documented survivor bias?

   iv. The higher risk nature of the US economy and securities markets?.

2. Please explain in detail why Ms. McShane started her risk premium analysis in 1947, when reliable indexes in Canada did not start until 1956 and/or other equity and bond data goes back at least until 1922. Please indicate the historic market risk premium in Canada using these two different start dates and provide all the annual data.

Response:

1. Ms. McShane does not have estimates of the various components referenced.

   Approximately 0.4% of the difference is due to higher equity returns in the U.S. (12.4% versus 12.0%) and the remainder is due to higher bond returns in Canada (0.7% based on income returns and 1.1% based on total returns). Ms. McShane's estimate of the market risk premium is consistent with the equity market returns (nominal) achieved in Canada and expected long-term Canada bond yields.

2. The question suggests that Ms. McShane restricted her risk premium analysis to the 1947 to 2009 period. As set forth in Appendix C, starting at page C-16, the analysis was conducted over the 1947-2009 period but supplemented by analysis over longer periods.

   The selection of the 1947-2009 period, as explained in Appendix C, page C-16, was intended to both reflect as broad a range of event types as possible and permit the assessment of investor expectations within the context of the current economic and capital market environment.

Further, the common stock data that date from 1956, that is, the returns for the TSE Composite Index in fact were not created until 1976 and backcast for 20 years to 1956.

The requested equity and bond returns and resulting historic risk premiums for Canada for the periods 1922 to 2009 and 1956 to 2009 are presented below:

	Canada	
	1922-2009	**1956-2009**
Canada Equity Return	11.6%	10.8%
Canada Total Bond Return	6.4%[1/]	7.6%
Risk Premium Based on Total Bond	5.2% [1/]	3.1%
Canada Income Return	6.2%	7.8%
Risk Premium Based on Income Return	5.4%	3.0%

[1/] The calculations are based on data for 1924-2009 because Ms. McShane does not have the total bond returns for the earlier years.

These values are based on the following data:

	Canadian Stock Returns	Canadian Total Bond Returns	Canadian Income Bond Returns
1922	19.6%		5.5%
1923	7.6%		5.2%
1924	11.3%	7.8%	5.1%
1925	28.7%	5.2%	5.0%
1926	24.4%	5.4%	5.0%
1927	44.9%	10.2%	4.7%
1928	32.9%	0.6%	4.6%
1929	-11.6%	2.3%	5.0%
1930	-30.9%	9.3%	4.8%
1931	-33.0%	-5.0%	4.7%
1932	-12.9%	12.4%	5.2%
1933	51.6%	7.4%	4.7%
1934	20.3%	19.7%	4.0%
1935	30.6%	0.8%	3.6%
1936	25.4%	11.1%	3.0%
1937	-15.8%	-0.6%	3.2%
1938	9.1%	5.6%	3.1%
1939	0.2%	-3.0%	3.2%
1940	-19.1%	8.7%	3.3%
1941	1.9%	3.8%	3.1%
1942	14.0%	3.1%	3.1%
1943	19.7%	3.9%	3.0%
1944	13.5%	3.2%	3.0%
1945	36.1%	5.2%	3.0%
1946	-1.5%	6.0%	2.6%
1947	0.3%	3.2%	2.6%
1948	12.1%	-2.4%	3.0%
1949	22.6%	4.9%	2.9%
1950	48.4%	-0.1%	2.9%
1951	24.0%	-3.1%	3.3%
1952	-0.4%	2.0%	3.6%
1953	2.2%	3.6%	3.8%
1954	39.1%	10.0%	3.2%
1955	27.8%	-0.3%	3.2%
1956	13.2%	-3.6%	3.7%
1957	-20.6%	5.9%	4.2%
1958	31.3%	-5.7%	4.2%
1959	4.6%	-4.4%	5.2%
1960	1.8%	7.1%	5.3%
1961	32.8%	9.8%	5.2%
1962	-7.1%	3.1%	5.2%
1963	15.6%	4.3%	5.2%
1964	25.4%	7.0%	5.3%
1965	6.7%	1.0%	5.3%

	Canadian Stock Returns	Canadian Total Bond Returns	Canadian Income Bond Returns
1966	-7.1%	1.6%	5.8%
1967	18.1%	-2.2%	6.1%
1968	22.5%	-0.8%	7.0%
1969	-0.8%	-2.0%	7.9%
1970	-3.6%	22.0%	8.2%
1971	8.0%	11.6%	7.2%
1972	27.4%	1.1%	7.5%
1973	0.3%	1.7%	7.8%
1974	-25.9%	-1.7%	9.3%
1975	18.5%	2.8%	9.4%
1976	11.0%	19.0%	9.6%
1977	10.7%	6.0%	9.1%
1978	29.7%	1.3%	9.7%
1979	44.8%	-2.6%	10.7%
1980	30.1%	2.1%	13.2%
1981	-10.3%	-3.0%	16.3%
1982	5.5%	43.0%	15.2%
1983	35.5%	9.6%	12.5%
1984	-2.4%	15.1%	13.5%
1985	25.1%	25.3%	11.6%
1986	9.0%	17.5%	9.9%
1987	5.9%	0.5%	10.4%
1988	11.1%	10.5%	10.7%
1989	21.4%	16.3%	10.4%
1990	-14.8%	3.3%	11.4%
1991	12.0%	24.4%	10.2%
1992	-1.4%	13.1%	9.1%
1993	32.6%	22.9%	8.1%
1994	-0.2%	-10.5%	9.0%
1995	14.5%	26.3%	8.6%
1996	28.4%	14.3%	7.8%
1997	15.0%	17.5%	6.6%
1998	-1.6%	14.1%	5.6%
1999	31.7%	-7.2%	5.8%
2000	7.4%	13.6%	6.0%
2001	-12.6%	3.9%	5.9%
2002	-12.4%	10.1%	5.8%
2003	26.7%	8.1%	5.3%
2004	14.5%	8.5%	5.1%
2005	24.1%	15.1%	4.6%
2006	17.3%	3.2%	4.2%
2007	9.6%	3.3%	4.0%
2008	-33.0%	13.7%	4.1%
2009	35.1%	-4.3%	3.8%

Public Intervenor
Interrogatory No. 28

Reference: Exhibit B – Expected Inflation and Returns

Interrogatory:

1. In her discussion of the earned equity market returns on Page 47, please confirm that these are nominal (i.e., actual) returns and Ms. McShane is using them as a forecast of future nominal returns to estimate the market risk premium.

2. Is it Ms. McShane's view that investors ignore the expected rate of inflation when determining their fair (nominal) rate of return; that is, the expected equity return was the same when inflation was over 10% in the 1970s as it is now when it is about 2.0%? If this is her judgment, please provide any citations to financial theory that indicate that the expected rate of inflation has no impact on an equity holder's required or fair nominal rate of return.

3. Ms. McShane finishes with an expected rate of return on the equity market of 11.5-12.0%. Please provide any and all current strategy or analyst reports that support a long-run equity market return in Canada or the US of this order of magnitude.

4. In discussing the decline in the long Canada bond yield, Ms. McShane has indicated that the expected rate of inflation is one factor that has caused this nominal yield or expected rate of return to decline. Please provide references to the literature that confirm that expected rates of return (or yields) on Canada bonds incorporate an expected inflation rate.

5. Please indicate why Ms. McShane believes that bond investors incorporate an expected rate of inflation into their expected nominal rate of return on long Canada bonds and yet equity investors do not. Please indicate by reference to the literature why Ms. McShane believes that equity investors behave differently to bond investors.

6. If Ms. McShane does believe that equity and bond investors behave differently with respect to inflation, please discuss in detail why they couldn't also react differently in terms of risk perception and why, as a result, yields on corporate debt could behave differently from expected returns on equities during a financial crisis.

7. Can Ms. McShane please confirm that when the required rate of return on a bond goes up, its price falls; that is, that bond prices and interest rates are inversely related?

8. Can Ms. McShane confirm that when expected inflation persistently increased until 1981, the expected return on long Canada bonds (yield) went up, causing losses and lower realised returns on long Canada bond portfolios? If not, why not?

9. Conversely can Ms. McShane confirm that when inflation came down, so did expected returns and yields on long Canada bonds, thus causing very high realised returns on long Canada bond portfolios? If not, why not?

10. Please confirm that if equity holders behaved the same way as bond holders, then higher expected inflation would similarly caused higher expected rates of return, causing prices to drop and resulting in lower realised equity returns. If not, why not?

Response:

1. It is confirmed.

2. Ms. McShane does not state that the expected equity return is the same at different levels of inflation or that the expected rate of inflation has no impact on the expected equity return. See page C-21 for a discussion of the impact of expected inflation on expected returns. The impact of inflation on actual equity market returns is discussed in Appendix C, page C-21 to C-22.

3. Ms. McShane is not aware of any strategist or analyst reports that estimate the expected rate of return at 11.5% to 12.0%. However, Ms. McShane would point out that her estimate of the expected rate of return, based on an analysis of historic returns, is, consistent with the discussion at pages C-5 to C-7, an arithmetic average, which is what is called for in estimating the cost of capital. When there is volatility in the returns, the arithmetic average annual return will always be higher than the compound average return, which is what analysts and strategists are likely to be estimating, consistent with the manner in which achieved returns are reported for investment performance purposes. The arithmetic average is approximately equal to the compound average plus one-half the variance in the return. Between 1924 and 2009, the variance in annual stock market returns in Canada has been 3.5%. Based on the historical variance, a long-run compound return of 10% would be approximately equal to an arithmetic average return of 11.75% (10% + ½ of 3.5%).

4. Any basic finance textbook would confirm that. For example, Eugene Brigham, *Fundamentals of Financial Management*, 7th edition, Fort Worth, TX: Dryden Press, 1995 states: "Inflation has a major impact on interest rates because it erodes the purchasing power of the dollar and lowers the real rate of return on investment…Investors are well aware of all this, so when they lend money, they build in an inflation premium (IP) equal to the expected inflation rate over the life of the securities."

5. Unlike bond investors whose investment is made at a fixed coupon rate, corporate earnings, from which equity investors ultimately derive their return, are better able to keep pace with the rate of inflation. As a result, unlike bond investors, investors in equities would not require a premium of the same magnitude to compensate for the possibility that higher than expected inflation will erode their return. In Basil Copeland, "Inflation, Interest Rates and Equity Risk Premia", *Financial Analysts Journal*, May-June 1982 (pages 32-43), the author states: "With uncertain inflation, the bond investor faces substantial risk of capital loss,

whereas the firm's ability to raise prices offers some protection to the shareholders." In James Farrell, Jr., "The Dividend Discount Model: A Primer", *Financial Analysts Journal*, Nov-Dec 1985 (pages 16-25), the conclusion is reached that "These data indicate that, over the long term, corporations have been able to offset inflation and provide a significant real return to investors. Over shorter intervals, however, corporate performance has been less steady. On balance, it appears that stocks, while exposed to purchasing power risk, are less susceptible than long-term bonds or preferred stocks."

6. Ms. McShane does not disagree that individual types of securities may behave differently at different points in time, depending on various factors, including the prevailing degree of risk aversion, the perceived risks (e.g., inflation) associated with different types of securities and the demand for and supply of different types of securities. However, an increased risk of default related to an increase in the risk of the underlying corporate activity, leading to increased credit spreads, a priori could be expected to correspond to an increase in equity risk (since equity holders are subordinate to debt holders). Various studies have shown a positive correlation between credit spreads and the equity risk premium, including J.R. Graham and C.R. Harvey, *The Equity Risk Premium amid a Global Financial Crisis*, 2009 and R.S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management*, Spring 1986.

7. It is confirmed.

8. It is confirmed.

9. It is confirmed.

10. If equities had the same characteristics as bonds and equities behaved the same as bonds, that would be true. Please see response to 6. above

Public Intervenor
Interrogatory No. 29

Reference: Exhibit B – Portfolio Diversification

Interrogatory:

1. On Page 44-45, Ms. McShane uses the ratio of standard deviations as a measure of risk. Recognizing that from her resume, she is a Chartered Financial Analyst (CFA), can she reference one paper on the CFA syllabus that indicates that this is an appropriate measure of risk for an individual security in contrast to a portfolio of securities?

2. Please indicate the approximate proportion of trading on the NYSE by individuals (retail) versus institutions, and identify one institution that holds an undiversified portfolio consisting of one security.

3. Can Ms. McShane confirm, then, when securities have less than perfect correlation, the standard deviation of the portfolio is generally less than that of the individual securities? If not, why not? Please explain in detail.

4. Can Ms. McShane confirm that 7 of the TSX sub-indexes in her Schedule 16 have higher average standard deviations than the TSX index, one basically the same (consumer discretionary), and that only the consumer staples and utilities have smaller standard deviations? Can she also confirm that this is what we would expect from portfolio diversification; that is, that the overall market is less risky than most of the constituents?

5. Can Ms. McShane confirm that her approach of using relative standard deviations as a risk measure would indicate that the expected return on 7 of the TSX sub indexes would then be higher than that of the market as a whole? If not, why not?

6. Since the market is simply the weighted average of all the sub indexes, can Ms. McShane explain how the weighted average of the expected returns from these sub indexes (7 of which are riskier than the market, one the same and only two lower) can also arithmetically be the expected market return? That is, for example, if two securities are both riskier than the portfolio, and their expected returns are 10% and 12%, how can the simple average of these two of 11% also be the expected return on the portfolio, which is lower risk than either of them?

7. Further to (5) above, if the expected return on the market is lower than that of 7 of the sub indexes, equal to one, and higher than the two low risk sub indexes, please indicate how much lower the expected return on the two low risk sub indexes have to be in order for the arithmetic to add up. Please provide a specific example calculation to support her hypothesis.

Response:

1. Ms. McShane has not reviewed the CFA syllabus. Standard deviations are a widely accepted measure of stand-alone risk.

2. Ms. McShane does not have the requested information. However, the proportion of the outstanding market capitalization of stocks covered by *Value Line* held by retail investors at the beginning of 2010 was approximately 45%. She would expect that there are no institutional investors that hold security portfolios consisting of a single security.

3. It is confirmed.

4. Both statements are confirmed.

5. It is not confirmed. Ms. McShane's relative risk adjustment is calculated by dividing the standard deviation of the utility index by the simple mean (and median) of the standard deviations of the 10 sub-sector indices including the utility index **not** the standard deviation of the S&P/TSX Composite as suggested by the question. Calculated relative to the average of the 10 sector indices, only 5 sub-sectors would have a relative risk adjustment of approximately 1 or more. See the table below.

S&P/TSX Sub-Sector Indices as a Percent of	
Mean of 10 Sector Indices	
Consumer Discretionary	**0.71**
Consumer Staples	**0.62**
Energy	**1.07**
Financials	**0.77**
Health Care	**1.19**
Industrials	**0.89**
Information Technology	**2.06**
Materials	**1.08**
Telecommunication Services	**0.96**
Utilities	**0.65**

6. Please see response to 5. above. As stated in Appendix C, page C-25, the ratio of standard deviations is used as an estimate of the "relative market volatility" of the utility sub-sector index to the simple average of the 10 sub-sector indices.

7. Please see response 5. above.

Public Intervenor
Interrogatory No. 30

Reference: Exhibit B – Beta Adjustment Formula

Interrogatory:

1. On Page 45, Ms. McShane notes a "widely used beta adjustment formula." Please indicate any Canadian regulatory body that has explicitly supported the use of such an adjustment scheme.

2. Please confirm that this beta adjustment scheme almost always increases the betas of low risk securities since they are averaged with the overall market average of 1.0. If not, please explain why not

3. Please confirm that the beta adjustment mechanisms were introduced after research by Professor Marshall Blume suggested it as a way to compensate for the underperformance of the CAPM for low risk securities, and that this was when the risk free rate used in the CAPM was the Treasury Bill yield. If not, why not?

4. Please provide any research that suggests that a similar adjustment mechanism is needed when the risk free rate used in the CAPM is the long term Canada bond yield, rather than the Treasury Bill yield.

5. Since Ms. McShane thinks US data is relevant to Canadian utilities, please provide similar beta estimates to those in Schedule 17 for the TSX sub indexes and Schedule 19 for Canadian utilities, where the market return is that on the S&P500, both with and without an adjustment for the value of the C$.

6. In Ms. Shane's judgment, which is the better relative risk assessment for Canadian utilities: their risk relative to the Canadian market; relative to the US market, or relative to the world market? Please support her recommendation with the appropriate beta coefficients and estimate of the overall market risk premium.

Response:

1. Ms. McShane is not aware of any Canadian decisions which have specifically relied on the adjustment methodology, although it is widely relied upon by commercial providers of beta as well as by U.S. regulators.

2. It is confirmed. As low risk securities typically have betas less than one, the methodology necessarily increases the beta as it adjusts the 'raw' betas toward the equity market beta of 1.0.

3. It is confirmed.

4. The study by Eugene Fama and Kenneth French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives,* Vol. 18, No. 3, Summer 2004, stated that the relationship between beta and average return is much flatter than the CAPM would predict. Specifically, based on analysis covering 1928 to 2003, they showed that the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return. In the U.S., the spread between the one-month Treasury bill and the long-term government bond yield historically has been approximately 1.5%. If one assumes that short-term Treasury bill rate is 3.5%, the market return is 12.0% and the "raw" beta of the portfolio is 0.50, using the short-term rate produces a CAPM return of 3.5% + 0.50 (12.0%-3.5%) = 7.75%. Using the long-term yield of 5.0% produces a CAPM return of 5.0% + 0.50 (12.0% - 5.0%) = 8.50%. Using the long-term yield in the CAPM rather than the short-term Treasury bill rate thus adjusts the cost of equity upward by 0.75 percentage points, well below the 2.8 percentage point difference in the actual versus predicted return for the lowest beta portfolio. The magnitude of the shortfall between the underperformance of the CAPM of the lowest beta portfolio and the adjustment implicit in the use of a long-term government bond yield strongly suggests that the beta adjustment mechanism is needed.

5. Please see the attached TSX and Canadian utility Beta information.

6. While Ms. McShane uses U.S. market data and Canadian data to develop the equity risk premium, the resulting value is a premium for Canada and the relative risk adjustment for a benchmark Canadian utility is relative to the Canadian market.

Public Intervenor
Interrogatory No. 31

Reference: Exhibit B – Utility Risk Premiums
Interrogatory:

1. On Page 48, Ms. McShane begins her discussion of historic utility risk premiums in the US and Canada. Please confirm that these risk premiums, by definition, reflect the historic risk that investors have been exposed to over this period.

2. Please indicate how Ms. McShane has adjusted for the following reductions in risk that have resulted from regulatory actions:
   i. Introduction of forward test years;
   ii. The use forward averaging of the rate base;
   iii. The introduction of purchased gas variance accounts;
   iv. The removal of the merchant function;
   v. The removal of non-core monopoly services such as water heater rentals from the rate base;
   vi. Rate rebalancing when customer mix change;
   vii. The movement to fixed cost rate structures from variable rates;
   viii. The introduction of performance-based regulation.

3. Conversely, is it Ms. McShane's judgment that none of the factors in (2) above have reduced the risk of regulated utility operations in Canada? If the answer is that in her judgment they have reduced risk, to what extent should her average utility risk premium estimate be lowered as an estimate of the current or forward estimate of utility risk that reflects this risk reduction?

Response:

1. It is confirmed.

2. Ms. McShane notes that the 4.5% referenced risk premium represents the difference between the achieved equity market returns for Canadian utilities and total bond returns. The 4.5% is not Ms. McShane's estimate of the utility market risk premium and return. Ms. McShane did not make any adjustments for the factors listed in the question. The returns that have been achieved over the longer term would capture various factors, both positive and negative, including the rate of expansion of the utility industries, the evolution of the regulatory regime over time, the trends in allowed returns, and the reaction of the capital markets to macroeconomic factors (e.g., increases in inflation and interest rates, followed by decreases in inflation and interest rates). Ms. McShane has no evidentiary basis for concluding that the returns achieved on average over the longer-term are not reflective of the returns that utility investors expect based on the risks that they face under current circumstances. As suggested at lines 1237-1238 of her testimony, there is no evidence of a secular upward or downward

trend in the market returns achieved by utilities that would warrant a reduction to the historic returns for the purpose of estimating utility investors' future return expectations.

3. No adjustment to Ms. McShane's estimate of the utility risk premium is required. Please see response to 2. above.

Public Intervenor
Interrogatory No. 32

Reference: Exhibit B – Growth Forecasts

Interrogatory:

1. On Page 46, Ms. McShane discusses her DCF estimates based on US utilities and indicates that they are based on IBES analyst growth forecasts. Please indicate any and all evidence that Ms. McShane is aware of that indicates that analyst growth forecasts are unbiased estimates of future growth rates.

2. In Schedule 20, Ms. McShane indicates that the average forecast growth rate for her US utilities in 2009 is 5.4%. Please confirm that this is an infinite growth rate and that it exceeds the forecast growth rate for the US economy.

3. Ms. McShane also indicates that the average IBES growth rate for 1995-2009 was 4.9%. Please indicate the average compound growth rate in dividends and earnings per share for her US sample over this same time period.

Response:

1. Ms. McShane is aware that there is a body of studies that conclude that analysts' forecasts are upwardly biased. However, the studies and conclusions regarding upward bias have not been specific to utilities. The potential upward bias of the IBES growth rates for the U.S. utilities was assessed in three separate ways. First, as discussed in the testimony, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the I/B/E/S forecasts were compared to the consensus forecasts of long-term growth. For the benchmark sample of utilities used to estimate the relationship between the DCF-based cost of equity, interest rates and spreads, the average expected long-term growth rate, as estimated using analysts' forecasts, for the entire 1995-2009 period of analysis was 4.8%. That growth rate is lower than the expected long-term nominal growth in the economy as a whole has been over the same period. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (Blue Chip *Economic Indicators*, March and October editions, 1995-2009), has been 5.2% over the same period covered by the DCF-based analysis. The similar expected nominal growth in the economy compared to the IBES forecasts suggests that the IBES forecasts are not upwardly biased.

   Second, the IBES forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* has no incentive to "inflate" its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Over the period of analysis (1995-2009), the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 5.4%, compared to the average IBES long-term earnings growth rate forecast for the same companies of 4.8%. Again, the higher *Value Line* than IBES forecasts suggests that the IBES forecasts are not upwardly biased.

Third, allowed returns for U.S. utilities are derived primarily through reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favor the use of forecast growth, while another may favor the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to the estimated DCF costs of equity for the benchmark sample of U.S. utilities (over the same period 1995-2009), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the various DCF models as follows:

RRA Allowed Return 1995-2009	**10.8%**	**Difference from RRA**
Constant Growth	9.9%	-0.9%
Sustainable Growth	9.9%	-0.9%
Three Stage Growth	9.5%	-1.3%

This comparison lends further support to the conclusion that the IBES forecasts have not been upwardly biased.

2. Please see response to Public Intervenor Interrogatory No. 26(2).

3. The average expected long-term growth rate, as estimated using analysts' forecasts, for the 1995-2009 period was 4.8% (Appendix B, page B-6) not 4.9% as indicated in the question. The compound growth rate for Ms. McShane's U.S. sample from 1995-2009 in dividends was 2.9% and was 4.1% in earnings per share.

Public Intervenor
Interrogatory No. 33

Reference: Exhibit B – Market-to-Book Ratios

Interrogatory:

1. On Page 50, Ms. McShane estimates financing costs by targeting a market-to-book value of 1.05-1.10. Please justify the choice of 1.05-1.1.

2. For all the US utilities in her US proxy group, please provide the market-to-book ratio for each year back to 1990.

3. For all of her Canadian utilities in Schedule 19, please provide the market-to-book ratios back to 1990 and indicate, whether in Ms. McShane's judgment, there has been any change in the average market-to-book ratio since the introduction of ROE adjustment mechanism for the test year 1995.

Response:

1. As stated at Exhibit B, McShane Evidence, page 50 starting at line 1264, the "financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover a number of factors including: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; (3) a recognition that the financial risk inherent in the market value capital structures is lower than the financial risk represented by their book value capital structures; (4) the "fairness" principle."

   A reduction in the market/book ratio of the utility to a level below 1.0 is an indicator of the impairment of financial integrity. The discounted cash flow and risk premium results are "bare-bones" costs, i.e., the return which conceptually, if applied to the book value of equity, would cause the utility market/book ratio to equal 1.0. The incurrence of out of pocket financing costs (which are recovered indirectly through the allowed return on equity rather than as a line item in the revenue requirement), the potential for the share price to decline when additional shares are issued (market pressure) and the potential for an unforeseen break, i.e., a significant decline, in the equity markets when a utility is in the process of issuing new equity that could result in a utility issuing new shares at a market/book ratio below 1.0, all support providing, at the very least, a minimal adjustment to the "bare bones" cost of equity for financing flexibility to allow the maintenance of financial integrity. Studies conducted by ScotiaMcLeod, RBC Dominion Securities and others estimated these costs in the range of 5-10%. A financing flexibility allowance sufficient to maintain a market/book range of 1.05-1.10 provides, in Ms. McShane's judgment, an adequate cushion to prevent the impairment of financial integrity as defined above. However, the financing flexibility adjustment for a utility is intended to translate a return on market value into a return on original cost book value. As presented in Schedule 21, the incremental return required to account for the difference between market value and book value capital structures for the benchmark sample is estimated at between 80 and 150 basis points. Therefore, a financing flexibility allowance sufficient only to maintain a market/book in the range of 1.05-1.10, equivalent to approximately 50 basis points, does not fully address the comparable returns standard.

2. The market to book ratios for the U.S. benchmark utilities are shown below:

U.S. Benchmark Sample Market to Book Ratios

Company Name	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
AGL RESOURCES INC	1.69	1.82	1.94	1.90	1.50	1.90	1.81	1.72	1.70	1.40	1.74	1.64	1.94	1.99	1.84	1.81	1.88	1.73	1.46	1.59
CONSOLIDATED EDISON INC	1.20	1.42	1.56	1.49	1.14	1.35	1.19	1.63	2.04	1.36	1.49	1.51	1.55	1.51	1.50	1.55	1.55	1.46	1.10	1.25
NEW JERSEY RESOURCES CORP	1.36	1.54	1.58	2.13	1.46	1.78	1.85	2.08	2.18	2.35	2.18	2.23	2.45	2.34	2.45	2.89	2.19	2.13	2.08	2.19
NICOR INC	1.88	1.85	1.95	2.15	1.72	2.01	2.43	2.73	2.64	1.93	2.78	2.63	2.06	1.99	2.17	2.14	2.41	2.02	1.61	1.84
NORTHWEST NATURAL GAS CO	1.36	1.56	1.53	1.75	1.44	1.51	1.56	1.94	1.56	1.28	1.48	1.37	1.43	1.58	1.63	1.61	1.93	2.16	1.87	1.81
NSTAR	1.03	1.32	1.46	1.53	1.19	1.43	1.26	1.71	1.85	1.52	1.69	1.88	1.81	1.89	2.01	2.00	2.32	2.27	2.18	2.10
PIEDMONT NATURAL GAS CO	1.52	1.56	1.92	2.33	1.77	1.79	1.88	2.01	2.33	2.04	1.85	1.84	2.01	2.12	2.04	2.05	2.31	2.16	2.72	1.84
SOUTH JERSEY INDUSTRIES INC	1.34	1.44	1.62	1.66	1.25	1.58	1.52	1.88	1.67	1.71	1.70	1.76	1.69	1.80	2.12	2.16	2.21	2.22	2.30	2.09
WGL HOLDINGS INC	1.45	1.64	1.82	2.06	1.56	1.66	1.72	1.90	2.00	1.84	1.76	1.66	1.52	1.64	1.61	1.75	1.66	1.70	1.55	1.51

3. The market to book ratios for the Canadian utilities in Schedule 19 are shown below:

Canadian Utilities Market to Book Ratios

Company Name	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
CANADIAN UTILITIES -CL	1.44	1.43	1.35	1.62	1.44	1.49	1.63	2.07	2.28	1.74	2.12	1.92	1.77	1.88	1.81	2.51	2.57	2.31	1.85	1.81
EMERA INC	NA	NA	1.22	1.43	1.18	1.27	1.43	1.69	1.73	1.33	1.58	1.39	1.30	1.47	1.56	1.70	1.78	1.79	1.61	1.88
ENBRIDGE INC	NA	2.80	2.00	2.78	2.59	1.77	1.93	2.62	2.77	2.20	3.08	2.75	2.28	2.66	2.68	3.06	3.16	2.86	2.27	2.58
FORTIS INC	1.15	1.19	1.16	1.29	1.11	1.13	1.37	1.64	1.47	1.19	1.29	1.57	1.54	1.67	1.66	2.06	2.43	1.73	1.37	1.54
PACIFIC NORTHERN GAS L	1.05	1.17	1.34	1.70	1.46	1.44	1.43	1.77	1.57	0.95	0.41	0.46	0.92	0.98	1.02	0.91	0.82	0.85	0.59	0.78
TERASEN INC	1.29	1.27	1.14	1.23	1.00	1.17	1.33	1.85	1.98	1.55	1.58	1.51	1.44	1.75	1.95	NA	NA	NA	NA	NA
TRANSCANADA CORP	2.05	1.81	1.58	1.67	1.33	1.38	1.50	1.89	1.65	1.00	1.32	1.55	1.71	2.21	2.20	2.48	2.58	2.24	1.59	1.63

With respect to the question of whether there has been a change in the market to book ratio, the market to book ratios on average have been somewhat higher for the Canadian holding companies from 1997-2009 than they were from 1990-1996. However, there is nothing that suggests there is a connection between the higher market to book ratios since 1997 and the adoption of automatic adjustment formulas. A similar difference in the market to book ratios can be discerned for the benchmark U.S. utilities, which are not on formulas (average market to book ratio of 1.6 times from 1990-1996 versus 1.9 times from 1997-2009), for the TSX Composite (average market to book ratio of 1.6 times from 1990 to 1996 compared to an average of 2.2 times from 1997 to 2009), and the Standard & Poor's 500 in the U.S. (average market to book ratio of 2.5 times from 1990-1996 compared to 3.3 times from 1997-2009). Further, the market to book ratios reflect the returns earned and expected to be earned by the holding companies, which include significant operations not governed by the automatic adjustment formulas. The actual earned returns of the six companies shown on the attachment which still exist (Canadian Utilities Limited, Emera, Enbridge, Fortis, Pacific Northern Gas and TransCanada) had an average 1997-2009 ROE of approximately 12%, compared to the average allowed ROE over that same time period of approximately 9.5%.

Public Intervenor
Interrogatory No. 34

Reference: Exhibit B – Bond Ratings

Interrogatory:

1. On Page 52, Ms. McShane uses a sample of US utilities with BBB bond ratings as proxies for EGNB. Can Ms. McShane provide the net rate base and operating revenues for each utility in her US BBB sample in Schedule 22, as well as the same data for EGNB?

2. Can Ms. McShane explain why in her recent Gazifere testimony, she judged Gazifere be no better than a BBB, but used a different reference sample of US utilities and provided the same data as that requested in (1) above?

3. In terms of the Ibbotson small cap premium, can Ms. McShane confirm that this is for small cap stocks that are traded in the stock market, rather than small firms per se that are part of larger firms? If the answer is yes, can Ms. McShane confirm that small publicly traded firms do not have the same characteristics as divisions of publicly traded firms? If the answer is no, please indicate any and all studies she has done to show that small publicly traded firms in the Ibbotson small cap premium work have the same characteristics as EGNB.

Response:

1. Ms. McShane does not have the requested net rate base data. The 2009 total current operating revenue for the companies in the BBB sample as well as EGNB are presented in the table below:

	2009 $ Millions
EGNB	26
Energen Corp.	1,436
EQT Corp.	1,270
National Fuel Gas Co	2,058
ONEOK Inc.	11,112
Questar Corp	3,038

2. In the Gazifère testimony, the conclusion was drawn that, based on total business plus financial risk, the utility would be rated no higher than BBB. Consequently a sample of comparables was selected which focused on the rating (ratings in the range of BBB+ to BBB-) with no constraint on the business risk profile score. The resulting sample of proxy utilities had a "Strong" business profile score. For EGNB, since it is a higher business risk utility than Gazifère, my objective was to select a sample of proxies with a higher business risk

profile than the sample used for Gazifère. Specifically, with regard to EGNB, I concluded that it would likely have a business risk profile score of "Satisfactory", and given its capital structure, on the border between investment grade and non-investment grade. Thus, I selected a sample of proxies with a "Satisfactory" business risk profile. My selection was limited by the lack of utilities who are actually non-investment grade to companies with ratings in the BBB category.

3. It is confirmed both that the Ibbotson analysis is based on the returns of publicly traded stocks and that the characteristics of publicly traded stocks are different from those of small firms that exist as part of a larger firm when the smaller firms have the ability to rely on their parent for various forms of support (e.g., financial support or expertise). However, as a utility still in the development phase, EGNB faces some of the same issues (e.g., competitive pressures) as small firms generally. The purpose of utilizing the Ibbotson study findings on small size and returns was to provide an alternative measure of the incremental risk premium developed by reference to the sample of higher risk gas utilities. Based on the small cap premium studies, the estimate of the incremental risk premium warranted "if EGNB were a stand-alone publicly traded stock" was over 200 basis points based on the application of the CAPM. As noted in footnote 50 to Ms. McShane's testimony, the actual returns of small regulated companies have been 1.5 (geometric average) to 3 (arithmetic average) percentage points higher than the corresponding returns for large regulated companies. The combination of the approaches indicate that a 2.0-3.0 percentage point incremental risk premium of EGNB is reasonable.

Public Intervenor
Interrogatory No. 35

Reference: Exhibit B – ROE Formula

Interrogatory:

1. On Pages 54 and on, Ms. McShane discusses her ROE recommendations, but she does not indicate why she has not recommended the same ROE formula she has recommended in other 2010 rate cases. Please explain in detail why she has not recommended a new formula, and whether this was because EGNB specifically indicated a preference for a fixed ROE.

Response:

1. The evidence that Ms. McShane prepared for the purpose of this proceeding was in response to the Board's determination that it could review the cost of capital during the development period and its decision that it would do so. The filed evidence responds to the Board's directive. Ms. McShane did not recommend a formula in this case in light of the dynamic nature of EGNB's circumstances, including the continuing evolution of EGNB's risk profile, the uncertainty with respect to when the development period will be deemed by the Board to have ended and the length of time over which the cost of capital approved in this proceeding will be in place without further review.