by the proposed formula is significantly lower than revenue growth provided by recent cost of service regulation. The difference is the annual benefit to ratepayers.

5. The costs of a distribution utility are closely aligned with the number of customers it serves. Each new customer represents new capital costs associated with attachment to the system (mains, service lines, meters) and new operations and maintenance costs (customer care, meter reading, billing and collection). It is appropriate therefore that a revenue adjustment mechanism recognize the increase in the number of customers as the measure of system growth. In the proposed formula, system growth is recognized by expressing the revenue requirement on a per customer basis. It is also proposed that the number of customers used will be the *average* number of customers for the rate year.

Revenue Adjustment Formula

6. Enbridge Gas Distribution proposes a revenue cap, calculated on a per customer basis, adjusted annually as follows:

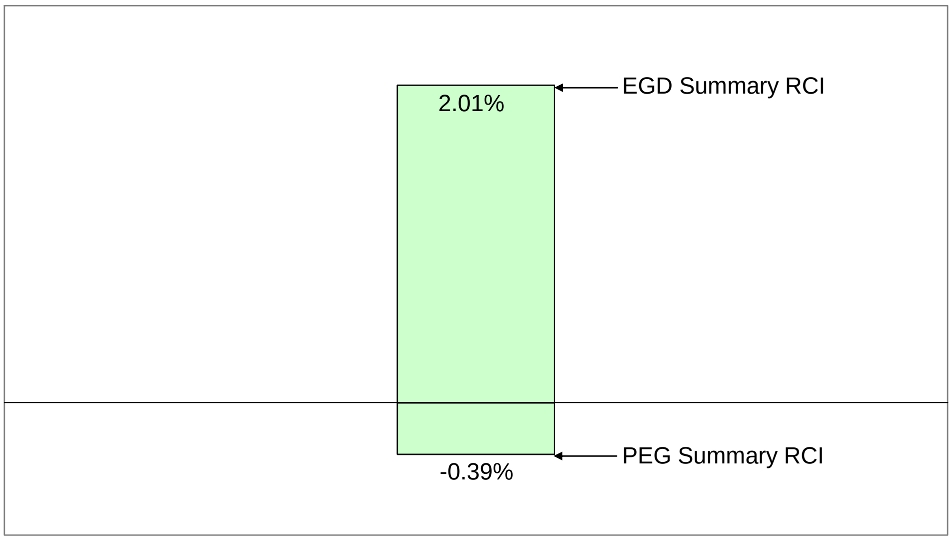
$$RR_t = \left(\frac{RR_{t-1}}{C_{t-1}}\right) * (1 + GDPIPI - X) * C_t + Y + Z$$ /c

where:

RR	= the revenue requirement
t	= the rate year
C	= the average number of customers
X	= the X factor or productivity challenge
GDP IPI	= the inflation factor, the GDP Price Index (Final Domestic Demand)
Y	= specific categories of expense, added at cost of service
Z	= exogenous factors, beyond management’s control

Witnesses: P. Hoey
R. Campbell
T. Ladanyi

Chart 2
Summary RCIs (No Growth)



33. This context demonstrates the reasonableness of the Company's proposal compared to PEG's recommendation. This proposal includes annual adjustments to key rate determinants rather than relying on an econometric estimation for five years. Finally, the annual application process with respect to volume and customer forecasts provides greater transparency for stakeholders as compared to PEG's rate or revenue indexes. Taken together, the Company's proposal is designed to satisfy the objectives for incentive regulation while reducing the potential for unintended consequences.

<u>Definition of Terms for the Proposed Formula</u>

34. This section proposes definitions for the terms in Enbridge Gas Distribution's proposed revenue cap formula, calculated on a per customer basis, as follows:

$$RR_t = \left(\frac{RR_{t-1}}{C_{t-1}}\right) * \left(1 + GDPIPI - X\right) * C_t + Y + Z$$ /c

Witnesses: P. Hoey
R. Campbell
T. Ladanyi

$$I_{TestYear} = \frac{1}{4}\left(AG^{Q2}_{TestYear-1} + AG^{Q1}_{TestYear-1} + AG^{Q4}_{TestYear-2} + AG^{Q3}_{TestYear-2}\right)$$ /c

where, for example,

$$AG^{Q2}_{TestYear-1} = 100\left(\frac{Index^{Q2}_{TestYear-1}}{Index^{Q2}_{TestYear-2}} - 1\right)$$

6. It is important to note that the calibration of the X factor is contingent on the selection of the inflation factor. Consequently, the choice of inflation factor may change subject to the outcome of any Board decision regarding X factor calibration.

Table 1
Business Conditions of EGDI and its PEG Peer Groups

Line No. [A]	Utility [B]	Province / State [C]	Region [D]	No. of Customers 2005 (Millions) [E]	Throughput 2005 (Bcf) [F]	Total Volume Per Customer 2005 (Mcf per Customer) [G]	Annual Customer Growth Rate 1997-2005 [H]	Miles of Distribution Main 2005 (Miles) [I]	Density [a] 2005 (Customer per Mile) [J]	Cast Iron Main Usage 2005 [K]
[1]	EGDI	ON	Canada	1.77	439	247	3.6%	19,261	92.1	1.8%
[2]	Washington Gas Light	VA, MD, DC	Southeast	1.00	171	170	2.9%	11,448	87.7	4.8%
[3]	East Ohio Gas	OH	Midwest and Plains	1.22	271	222	0.3%	19,200	63.5	0.7%
[4]	Pacific Gas & Electric	CA	California	4.13	709	172	1.4%	40,704	101.4	0.5%
[5]	Northern Illinois Gas / NICOR Gas	IL	Midwest and Plains	2.11	457	217	1.5%	31,411	67.1	1.5%
[6]	Southern California Gas	CA	California	5.33	761	143	1.3%	46,092	115.6	0.0%
[7]	Mountain Fuel Supply / Questar	UT, WY, ID	Southwest	0.82	126	153	3.5%	14,513	56.8	0.0%
[8]	Nstar Gas	MA	Northeast	0.25	58	229	1.0%	3,012	84.5	15.4%
[9]	Southwest Gas [b]	AZ, NV, CA	Southwest	1.65	235	143	5.1%	26,827	61.3	0.0%
[10]	Niagara Mohawk [c]	NY	Northeast	0.57	148	261	0.9%	8,351	67.8	9.2%
[11]	**Peer Group Mean**			1.90	326	190	2.0%	22,395	78.4	3.6%
[12]	**Peer Group Standard Deviation**			1.62	243	41	1.4%	13,995	19.0	5.1%

Notes:
[a] Density is calculated as Total Number of Customers / Miles of Distribution Main.
[b] Southwest Gas is a peer for EGDI if the GD capital costing method is used, but not if the COS capital costing method is used.
[c] Niagara Mohawk is a peer for EGDI if the COS capital costing method is used, but not if the GD capital costing method is used.

Sources:
[D2] - [D10] : "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," Pacific Economic Group (20 June 2007), Table 1, Pg. 20
[E1] : EGDI 2005 Annual Review
[E2] - [E10]: 2005 EIA Form 176
[F1] : EGDI Inc 2005 Annual Review
[F2] - [F10] : 2005 EIA Form 176
[H1] : EGDI Annual Review (1997-2005)
[H2] - [H10] : EIA Form 176 (1997-2005)
[I1] : EGDI
[I2] - [I10] : AGA EGUS Database
[K1] : EGDI
[K2] - [K10] : AGA EGUS Database

III. THE BOARD SHOULD NOT RELY ON THE RESULTS OF PEG'S ECONOMETRIC MODEL WITHOUT FURTHER INVESTIGATION AND TESTING

A. THE MODEL WILL ONLY BE RELIABLE IF IT IS SPECIFIED IN A WAY THAT CAPTURES ALL OF THE APPROPRIATE OUTPUT AND BUSINESS CONDITION VARIABLES THAT AFFECT GAS DISTRIBUTION COMPANY COSTS

There are several concerns that arise whenever an econometric model is employed to explain industry costs and prices, and particularly when the model's results are ultimately going to be relied on to predict the cost or productivity trend of a single firm in the industry. First, of course, the underlying sample data must be representative of the industry in question and it must span the relevant range of business and market characteristics that explain costs for the firm it is to be applied to. Second, the model must include all of the relevant variables that explain costs. So-called "omitted variables" are a standard source of error and bias in the estimated coefficients in such models. Third, the model should be stable in the sense that small changes in specification or underlying sample data do not produce significant changes

Table 2

PEG Ontario Econometric Cost Model Compared to PEG California Econometric Cost Model

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
VRC = Weather Adjusted Residential & Commercial Deliveries
VO = Other Deliveries
V = Total Throughput
NIM = % Non-Iron Miles in Distribution Miles
NE = Number of Electric Customers
UD = Urban Core Dummy
Trend = Time Trend

Explanatory Variable	Ontario Parameter Estimate	Ontario T-Statistic	California Parameter Estimate	California T-Statistic
L	0.244	15.52	0.197	72.72
LL	-0.343	-2.45	-0.121	-4.52
LK	-0.096	-6.75	-0.019	-0.91
LN	0.018	1.46	-0.019	-2.95
LVRC	-0.041	-3.59		
LVO	0.015	3.44		
LV			0.011	1.69
Ltrend	0.000	0.07		
K	0.532	85.67	0.593	191.61
KK	0.158	11.59	0.139	6.27
KN	-0.063	-4.48	0.028	4.11
KVRC	0.045	3.38		
KVO	0.015	3.73		
KV			-0.025	-3.60
Ktrend	0.007	6.60		
N	0.680	16.11	0.701	21.12
NN	0.069	1.83	-0.314	-4.35
NV			0.271	3.46
VRC	0.143	4.17		
VRCVRC	-0.168	-3.91		
VO	0.048	2.40		
VOVO	0.023	1.64		
V			0.165	5.12
VV			-0.238	-2.63
NIM	-0.507	-8.94	-0.503	-13.87
NE	-0.010	-8.43	-0.010	-10.81
UD	0.036	2.45	0.108	7.15
Trend	-0.014	-6.02	-0.007	-3.47
Constant	8.104	327.18	12.359	539.03
System Rbar-Squared	0.968		0.971	
Sample Period	1994 - 2004		1994 - 2004	
Number of U.S. Utilities	36		39	
Number of Observations	396		444	

Table 3

Econometric Cost Model for Gas Distribution

(Replicated from PEG New Zealand Study)

VARIABLE KEY

L = Labor Price
K = Capital Price
N = Number of Customers
V = Total Throughput
NI = % of Main that is Non-Cast Iron
M = Miles of Distribution Main

Explanatory Variable	Parameter Estimate	T-Statistic
L	0.227	57.78
LL	-0.401	-7.33
LK	-0.001	-0.06
LN	0.001	0.06
LV	0.058	5.95
LNI	-0.204	-7.47
LM	-0.048	-3.79
K	0.680	258.82
KK	0.058	3.05
KN	0.017	2.03
KV	0.028	5.10
KNI	0.121	4.74
KM	-0.051	-5.39
N	0.617	20.64
NN	0.141	1.57
NV	-0.060	-0.74
V	0.071	3.03
VV	-0.085	-1.17
NI	-0.661	-8.93
M	0.192	7.20
Constant	12.791	899.76
Trend	-0.011	-3.34
System Rbar-Squared	0.972	

Table 4
Business Conditions of EGDI and Northeast Utilities

Line No. [A]	Utility [B]	Province / State [C]	Region [D]	No. of Customers 2005 (Millions) [E]	Throughput 2005 (Bcf) [F]	Total Volume Per Customer 2005 (Mcf per Customer) [G]	Annual Customer Growth Rate 1997-2005 [H]	Miles of Distribution Main 2005 (Miles) [I]	Density [a] 2005 (Customer per Mile) [J]	Cast Iron Main Usage 2005 [K]
[1]	EGDI	ON	Canada	1.77	439	247	3.6%	19,261	92.1	1.8%
[2]	Baltimore Gas & Electric	MD	Northeast	0.63	103	163	1.4%	6,586	96.3	21.0%
[3]	Central Hudson Gas & Electric	NY	Northeast	0.07	16	222	1.8%	1,091	64.8	7.2%
[4]	Connecticut Natural Gas	CT	Northeast	0.15	27	177	1.1%	1,987	77.0	21.7%
[5]	ConEd of New York	NY	Northeast	1.05	235	222	0.3%	1,825	578.0	2.4%
[6]	Niagara Mohawk	NY	Northeast	0.57	148	261	0.9%	8,351	67.8	9.2%
[7]	New Jersey Natural Gas	NJ	Northeast	0.47	69	148	2.7%	6,475	71.9	1.6%
[8]	Nstar Gas	MA	Northeast	0.25	58	229	1.0%	3,012	84.5	15.4%
[9]	Orange and Rockland Utilities	NY	Northeast	0.12	27	217	1.2%	4,247	29.2	33.1%
[10]	PECO Energy	PA	Northeast	0.47	85	180	1.9%	6,542	72.1	12.9%
[11]	People's Natural Gas (PA)	PA	Northeast	0.36	71	200	0.3%	6,527	54.5	1.0%
[12]	P G Energy	PA	Northeast	0.16	48	300	1.2%	*	*	*
[13]	Public Service Electric & Gas	NJ	Northeast	1.71	356	208	1.3%	17,241	99.1	26.3%
[14]	Rochester Gas and Electric	NY	Northeast	0.29	52	178	0.6%	4,631	63.6	3.1%
[15]	Southern Connecticut Gas	CT	Northeast	0.17	67	385	1.3%	2,244	77.4	32.8%
[16]	Keyspan [b] [c]	NY, MA, NH	Northeast	2.54	490	193	1.1%	24,111	105.3	20.5%
[17]	**Northeast Utility Mean**			0.60	123	219	1.2%	6,776	110.1	14.9%
[18]	**Northeast Utility Standard Deviation**			0.66	131	58	0.6%	6,200	131.1	10.9%

Notes:
[a] Density is calculated as Total Number of Customers / Miles of Distribution Main.
[b] Keyspan includes Keyspan Energy Delivery New York, Keyspan Energy Delivery Long Island, Boston Gas, Colonial Gas and Energy North.
It excludes Essex Gas, for which the AGA and the EIA-176 database do not have 2005 data.
[c] PEG excludes Boston Gas and Keyspan Energy Delivery (New York) from its Ontario study, but includes them in its California study.
Boston Gas and Keyspan Energy Delivery (New York) are included (together with other Keyspan northeast utilities) in Table 4 as Keyspan.
[d] 2005 data was not available from the AGA for PG Energy.

Sources:
[D2] - [D16] : "Rate Adjustment Indexes for Ontario's Natural Gas Utilities," Pacific Economic Group (20 June 2007), Table 1, Pg. 20
[E1] : EGDI Inc 2005 Annual Review
[E2] - [E16]: 2005 EIA Form 176
[F1] : EGDI Inc 2005 Annual Review
[F2] - [F16] : 2005 EIA Form 176
[H1] : EGDI Annual Review (1997-2005)
[H2] - [H16] : EIA Form 176 (1997-2005)
[I1] : EGDI
[I2] - [I16] : AGA EGUS Database
[K1] : EGDI
[K2] - [K16] : AGA EGUS Database

IV. QUALIFICATIONS

I am an economist specializing in the fields of industrial organization, finance and energy and regulatory economics. I received a Ph.D. in Applied Economics and an M.S. in Management from the Massachusetts Institute of Technology, and a B.A. in Economics from Stanford University. I have been involved in research and consulting on the economics and regulation of the natural gas, oil and electric utility industries in North America and abroad for nearly twenty five years. I frequently have testified before federal, state and Canadian regulatory commissions, in federal court and before the U.S. Congress, on issues of pricing, competition and regulatory policy in these industries. Outside of North America, I have advised governments and regulatory bodies on the structure of their natural gas markets and the pricing of gas transmission services. These assignments have included testimony before the Australian Competition Tribunal and the U.K. Monopolies and Mergers Commission on the price control regime applied to British Gas,

RATE FILING PROCESS & REPORTING REQUIREMENTS

Rate Filing Process

1. Enbridge Gas Distribution adopts the Board Staff recommendation in its Discussion Paper regarding the rate filing process. Accordingly, the Company will file the following information annually by October 1st to set rates for each year of the IR plan period:
   - the forecast of degree days and corresponding volumes for the rate year;
   - the forecast of average number of customer bills for the rate year;
   - determination of the distribution revenue requirement adjustment factor, "GDP IPI – X"; /c
   - the determination of the inflation factor, "GDP IPI"; /c
   - the amounts for approved Y factors and associated cost-of-service distribution revenue requirement for the rate year;
   - the amounts for Z factors, if any, and associated cost-of-service distribution revenue requirement for the rate year;
   - deferral and variance account balances for the current rate year (eight months of actuals and four months of forecast) including the accounts proposed for clearance, the methodology for clearance and the proposed timing of the clearance. The clearance of deferral and variance accounts will occur each year in conjunction with the April 1st QRAM and will clear the prior years December 31st year end actual balances;
   - a draft rate order; and
   - a rate handbook and supporting documentation explaining how rates have been adjusted to reflect the distribution revenue requirement derived by the revenue cap per customer formula.

Witnesses: K. Culbert
A. Kacicnik