UNION GAS LIMITED – ENBRIDGE GAS DISTRIBUTION

MERGER APPLICATION AND RATE PLAN

EB-2017-0306/0307

CONSUMERS COUNCIL OF CANADA

COMPENDIUM

PANEL 1

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

MAADs Application

Reference: No-Harm Test

Question:
From Enbridge Inc.'s perspective what are the primary objectives of the merger? Under what circumstances would Enbridge Inc. not proceed with the merger? If the OEB reduced the rebasing deferral period to five years would the merger proceed?

Response

The primary objectives of the merger are to deliver benefits and value to both customers and the Amalco while continuing to provide safe and reliable service. It is not possible at this time to speculate on the circumstances under which Amalco may not proceed with the amalgamation.

However, if the OEB reduced the rebasing deferral period to five years, management would be unable to proceed with the amalgamation as proposed and outlined in the evidence. Also, see the response to Board Staff Interrogatory #4 found at Exhibit C.STAFF.4.

11. Enbridge's proposed Customized IR plan meets the Board's (and the Company's) objectives for an IR plan. It will benefit customers by ensuring safe and reliable service and enabling necessary safety and reliability spending. Customers and the Company will benefit from the establishment of rates for a five year period which will produce fair and predictable rates while reducing regulatory burden. The Customized IR plan embeds demonstrated productivity in both Operating and Maintenance ("O&M") and capital cost forecasts, and includes a number of incentive mechanisms that are designed to effect additional efficiencies that will be sustained beyond the end of the IR term.

12. The proposed Customized IR plan is also informed by the "Custom IR" option presented in the OEB's recent "Renewed Regulatory Framework" Report ("RRF Report"), and with IR plans used in other jurisdictions. In keeping with the expectations set out in the RRF Report, the proposed Customized IR plan creates "an appropriate alignment between a sustainable, financially viable [gas] sector and the expectations of customers for reliable service at a reasonable price".[1]

13. The key components of Enbridge's Customized IR Plan are set out in the following table:

	Components of IR Plan	**Details**
Items to be determined in the 2014 proceeding (EB-2012-0451)	Allowed Revenue amounts for 2014 to 2018	To be determined by summing together, for each year, the appropriate forecast level of operating costs, depreciation costs, taxes and cost of capital. These annual amounts are what Enbridge will be entitled to collect in rates each year.

[1] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, Ontario Energy Board, October 18, 2012, p. 1.

Witnesses: R. Fischer
M. Lister

debt requirement for the capital project and allowed ROE at the time of the application and be based on the Applicants' current capital structure at 64% debt and 36% equity.

4. Base Rate Adjustments

The Applicants propose to remove two adjustments that were the subject of settlements from prior proceedings and expire at the end of 2018. The first adjustment is an increase to Union's rates for the completion of the Board-approved deferred tax drawdown. The second adjustment is a decrease to EGD's rates for the smoothing of costs related to EGD's Customer Information System ("CIS") and customer care forecast costs. Prior to setting 2019 rates, the first year of the deferred rebasing term, Union and EGD's respective rates will be adjusted for the deferred tax drawdown and the CIS and customer care costs.

4.1 Union's Deferred Tax Drawdown

The Applicants propose to increase Union's 2018 Board-approved revenue by \$17.4[10] million pre-tax (\$12.8 million after-tax) to recognize the accumulated deferred tax balance (credit) is now fully amortized. This amount represents the difference between the credit to ratepayers included in 2018 rates, and the accumulated deferred tax balance at the end of 2018 of zero.

[10] \$12.819 million / (1-26.5%) = \$17.441 million (deferred tax adjustment included in 2018 rates of \$12.819 million after-tax divided by 1 minus the tax rate = \$17.441 million pre-tax).

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History of Deferred Tax Drawdown

In 1997, Union changed its accounting for utility income taxes from the tax allocation (or accrual) method to flow-through (or cash-basis) tax accounting. This change was adopted for rate-making purposes on a prospective basis and approved by the Board in its E.B.R.O. 493/494 Decision. The tax allocation method of accounting used for rate-making purposes prior to E.B.R.O. 493/494 resulted in an accumulated deferred tax balance.

One consequence of moving to flow-through accounting was the need for a transitional measure to address the existing accumulated deferred tax balance. In the E.B.R.O. 499 Board-approved Settlement Agreement, parties agreed that the accumulated deferred tax balance would be used to reduce Union's cost of service in future years by virtue of a drawdown mechanism.

The amount of the annual drawdown was based on the "natural" reversal of the timing differences (primarily related to Capital Cost Allowance ("CCA") and depreciation) which originally gave rise to the deferred tax balance. However, during IRM periods, parties agreed to normalize the drawdown to avoid annual rate adjustments. The Board-approved drawdown spanned a period of 20 years, beginning in 1999 and ending in 2018.

The drawdown of the deferred tax balance, starting with Union's last rebasing year (2013), is shown in Table 2 below. Ratepayers have received the benefit of lower rates for the past 20 years due to the drawdown of the deferred tax benefit.

Table 2
Deferred Tax Balance ($000's)

Line No.	Fiscal Year	Opening Balance	Drawdown Utilized (after-tax)	Closing Balance
1	2013	(79,263)	(15,169)	(64,094)
2	2014	(64,094)	(12,819)	(51,275)
3	2015	(38,456)	(12,819)	(38,456)
4	2016	(25,638)	(12,819)	(25,638)
5	2017	(25,638)	(12,819)	(12,819)
6	2018	(12,819)	(12,819)	-

Union's Proposal to Adjust Base Rates

Union proposes to increase 2018 Board-approved revenue by $17.4 million pre-tax since the annual drawdown of the deferred tax balance is completed in 2018. Ratepayers have received the benefit of lower rates for the past 20 years due to the drawdown of the deferred tax benefit. Union proposes the benefit be removed from rates now that the balance is zero and there is no further deferred tax drawdown credit to reduce rates.

4.2 EGD's CIS and Customer Care Forecast Costs

The Applicants propose to decrease EGD's 2018 Board-approved revenue by $4.9 million to recognize the approved CIS and customer care cost level of $126.2 million rather than the $131.1 million in 2018 Board-approved rates.

History of CIS and Customer Care Costs

EGD's CIS and Customer Care forecast costs and allowed revenue within rates for the years

2013-2018 were derived under an OEB-approved Settlement Agreement, EB-2011-0226.[11] In the Settlement Agreement, parties agreed that forecast CIS and customer care costs for the six year period would have a smoothing mechanism applied to them for determination of revenue and rate recovery purposes. The original forecast costs and revenues, based on forecast annual levels of customers at the time, were converted into approved cost per customer and smoothed cost per customer (revenue) unit rates. These unit rates were to be used annually, along with annually updated forecast levels of customers, to update the annual approved forecast costs and revenues for each year of the agreement.

The resulting impact of this smoothing mechanism was that in the years 2013-2015 the allowed costs and related cost per customer unit rates would be higher than the allowed revenues and related smoothed cost per customer unit rates recovered in rates, and, in the years 2016-2018 the approved costs and related cost per customer unit rates would be lower than the allowed revenues and related smoothed cost per customer unit rates recovered in rates.

In order to ensure the approved smoothing mechanism did not have any undue impact on earnings and earnings sharing results, parties agreed to establish a deferral account to record the annual difference between approved revenues and costs. The deferral account was not cleared on an annual basis, as over the six year term the account would in essence balance to zero (a

[11] EB-2011-0226, EGD Application Re: Approval of Revenue Requirement for CIS and Customer Care Costs from 2013to 2018.

unionGas

July 31, 2013

Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

RE: EB-2013- 0202 – Union Gas Limited
2014-2018 Incentive Regulation Application, Evidence and Settlement Agreement

Dear Ms. Walli,

Union Gas Limited ("Union") is requesting the approval of the Ontario Energy Board (the "Board") for a multi-year Incentive Regulation Mechanism ("IRM") that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period.

The proposed IRM parameters are the product of a comprehensive Settlement Agreement (the "Agreement") between Union and stakeholders which is attached at Exhibit A, Tab 2. The stakeholders who are party to the Agreement ("Stakeholders") have reviewed and support the evidence which is attached at Exhibit A, Tab 1. The Stakeholders are parties who participated in Union's 2008-2012 IRM proceeding and in the annual rate proceedings throughout the last IRM term.

Although Union and Stakeholders reached a comprehensive Agreement, it is acknowledged that Notice will be required and that other parties may be interested in participating in the regulatory approval process associated with Union's 2014-2018 IRM. A panel of Union witnesses will be available to address any questions or concerns from the Board or such other interested parties when the Agreement is presented to the Board.

Union respectfully requests that the Board expedite both the Notice and the presentation of the Agreement. This would allow Union, assuming the Board accepts the Agreement, to file for approval of 2014 rates in time to implement them for January 1, 2014.

P. O. Box 2001, 50 Keil Drive North, Chatham, ON, N7M 5M1 www.uniongas.com
Union Gas Limited

If you have any questions, please contact me at 519-436-5476.

Yours truly,

Chris Ripley
Manager, Regulatory Applications

cc: George Vegh, McCarthy Tetrault
EB-2011-0210 Intervenors

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule. B);

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving an incentive rate mechanism to determine rates for the distribution and transmission and storage of gas effective January 1, 2014;

APPLICATION

1. Union Gas Limited ("Union") is a business corporation, incorporated under the laws of Ontario, with its head office in the Municipality of Chatham-Kent.

2. Union conducts an integrated natural gas utility business that combines the operations of selling, distributing, transmitting and storing gas within the meaning of the *Ontario Energy Board Act, 1998* (the "Act").

3. Union hereby applies to the Ontario Energy Board ("OEB"), pursuant to section 36 of the Ontario Energy Board Act, 1998 (the "Act") for an order approving a multi-year incentive rate mechanism ("IRM") to determine rates for the regulated distribution, transmission and storage of gas effective January 1, 2014. Union seeks an IRM pursuant to a comprehensive Settlement Agreement between stakeholders and Union:

    (a) which applies to the base rates approved by the OEB commencing January 1, 2013 in EB-2011-0210, as adjusted to reflect the upfront productivity commitment of $4.5 million and the annual $3.152 million increase related to deferred taxes over the IRM term;

(b) in which the annual rate escalation is limited by a price cap index ("PCI"), where PCI growth is driven by an inflation factor ("GDP IPI FDD"), less a productivity factor of 60% of GDP IPI FDD;

(c) which exists for a 5 year term ending December 31, 2018;

(d) which has a provision for earnings sharing;

(e) which continues to pass-through routine gas commodity and other costs;

(f) which allows for non-routine cost adjustments for matters outside of the utility's control, including criteria for non-discretionary capital projects; and

(g) which maintains the existing level of service to customers.

4. Union also applies for an order to establish the following deferral accounts effective January 1, 2014:
   - Normalized Average Consumption Deferral Account (179-XXX)
   - Tax Variance Deferral Account (179-XXX)
   - Unaccounted for Gas ("UFG") Volume Variance Deferral Account (179-XXX)

5. Union also applies to the OEB for such interim orders approving interim rates and accounting orders as may from time to time appear appropriate or necessary.

6. Union further applies to the OEB for all necessary orders and directions to provide for pre-hearing and hearing procedures for the determination of this application.

7. This application is supported by a comprehensive settlement agreement and supporting reports.

8. The persons affected by this application are the customers resident or located in the municipalities, police villages and First nations reserves served by Union, together with those to whom Union sells gas, or on whose behalf Union distributes, transmits or stores gas. It is impractical to set out in this application the names and addresses of such persons because they are too numerous.

9. The address of service for Union is:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1
Attention: Chris Ripley
Manager, Regulatory Applications

Telephone: (519) 436-5476
Fax: (519) 436-4641

- and -

McCarthy Tetrault LLP
Suite 5300, TD Bank Tower
P.O. Box 48
66 Wellington Street West
Toronto, Ontario
M5K 1E6
Attention: George Vegh

Telephone: (416) 601-7709
Fax: (416) 868-0673

DATED: July 31, 2013

UNION GAS LIMITED

1.0 INTRODUCTION

Union Gas Limited ("Union") is requesting the approval of the Ontario Energy Board ("Board") for a multi-year Incentive Regulation Mechanism ("IRM") that will be used to set Union's regulated distribution, transportation and storage rates over the 2014 to 2018 period. The purpose of this evidence is to support that request. With the exception of the changes outlined in this evidence, Union's 2014-2018 IRM is consistent with the IRM approved by the Board and in place over the 2008-2012 period.

A summary of the proposed 2014-2018 IRM parameters is found at Table 1 below:

Table 1
Union Price Cap Plan Proposal Summary

Parameter	2008-2012 Approved IRM	2014- 2018 Proposed IRM
Base Rate Adjustments	2007 Board-approved revenues adjustments: 1. Decrease base revenues by $1.9 million to levelize deferred taxes over the 2008-2012 period; 2. Decrease base revenues by $1.0 million for reduction in regulatory budget; 3. Increase S&T margins by $4.3 million; and, 4. Reduce base revenues by $1.6 million related to GDAR.	2013 Board-approved revenues adjustments: 1. Increase base revenues by $3.152 million to levelize deferred taxes over the 2014-2018 period; 2. Decrease base revenues by $4.5 million as a further upfront productivity commitment by Union; and, 3. No adjustments related to Winter Warmth/LEAP during the IRM term.
Rate Mechanism	Price Cap Index	Price Cap Index
Inflation Factor (I)	GDP IPI FDD Canada index (average of annualized quarterly changes of the last four quarters – Q2 to Q2)	GDP IPI FDD Canada index (average of annualized quarterly changes of the last four quarters – Q2 to Q2)

Productivity Factor (X)	Fixed at 1.82% for each year of the IRM term	60% of GDP IPI FDD for each year of the IRM term
Weather Methodology	2007 Board-approved 55:45 blend of 30-year average and 20-year declining trend weather methodology	2013 Board-approved 50:50 blend of 30-year average and 20-year declining trend weather methodology
Normalized Average Use Factor (NAC)	Rates adjusted annually to reflect changes in General Service normalized average use (AU)	Rates adjusted annually to reflect changes in General Service normalized average consumption (NAC) (including LRAM for General Service rate classes)
Y Factors	Pass through treatment for: • Upstream gas costs • Upstream transportation costs • Incremental DSM costs • LRAM volume reductions (for all rate classes) • Elimination of the Long-term Storage Premium per the NGEIR Decision	Pass through treatment for: • Upstream gas costs • Upstream transportation costs • Incremental DSM costs • LRAM volume reductions for contract rate classes
Y Factor: Major Capital Projects	No Y factor treatment	Y factor for Major Capital Projects that meet certain criteria set out in Exhibit A, Tab 2, Section 6.6 and described in more detail below. The Brantford-Kirkwall and Parkway D Compressor and the Parkway West projects (EB-2013-0074 and EB-2012-0433) as filed meet the criteria
Y Factor: Unaccounted For Gas (UFG) Volume Variances	No Y factor treatment	Y factor treatment for UFG volume variances with a symmetrical dead-band of +/- $5.0 million around amounts built into rates
Z Factors	Z factor treatment for certain non-routine adjustments subject to criteria including a materiality threshold of $1.5 million	Z factor treatment for certain non-routine adjustments subject to criteria including a materiality threshold of $4.0 million. Z factor criteria amended to reflect EB-2011-0277 Decision

Tax Changes	50/50 sharing of tax changes	50/50 sharing of tax changes and establish a deferral account to capture amounts for disposition
Term of Plan	5 years starting in 2008	5 years starting in 2014
Earnings Sharing Mechanism	Earnings Sharing Mechanism above benchmark ROE adjusted annually using the Board's formula. Earnings Sharing Mechanism: 0-200 bps – No sharing 201-300 bps – 50:50 sharing Over 300 bps – 90:10 in favour of ratepayers	Earnings Sharing Mechanism above the 2013 Board-approved ROE of 8.93% for each year of the IRM. Earnings Sharing Mechanism: 0-100 bps – No sharing 101-200 bps – 50:50 sharing Over 200 bps – 90:10 in favour of ratepayers
Off-Ramps	Initial off-ramp if normalized utility earnings exceed 300 bps in any year of the IRM. The initial off-ramp was replaced with 90:10 sharing of utility earnings in excess of 300 bps in favour of ratepayers	No off-ramp
Marketing Flexibility	Flexibility to develop new services subject to Board approval	Flexibility to develop new services subject to Board approval
Reporting	• RRR filings made available • 18 financial schedules for prior actual year	• RRR filings made available • 18 financial schedules for prior actual year • Unregulated Plant Continuity • Service Quality Indicator Results • Audited financial statements for utility operations

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Annual Stakeholder Meeting	None	Annual funded stakeholder meeting that will: • Review prior year's financial statements • Explain market conditions and trends • Present the gas supply plan • Present new major capital projects • Present results of customer surveys
Rate Setting Processes	• File annual rate setting application by September 30 using IR mechanism including PCI, Y factors, approved Z factors and AU • File annual application for disposition of non-commodity deferral account and earnings sharing balances • File Quarterly Rate Adjustment Mechanism per EB-2008-0106	• File annual rate setting application by September 30 using IR mechanism including PCI, Y factors, approved Z factors and NAC • File annual application for disposition of non-commodity deferral account and earnings sharing balances • File Quarterly Rate Adjustment Mechanism per EB-2008-0106
Rebasing	Full cost of service filing for 2013 regardless of whether or not to be used for rate setting	Full cost of service filing for 2019 regardless of whether or not to be used for rate setting. Subject to agreement to extend the IRM term

As demonstrated by Table 1 above, Union's proposed 2014-2018 IRM is consistent with its prior IRM. The main differences are:

- An X factor that is a percentage of GDP IPPI FDD rather than a fixed inflationary adjustment;
- Y factor treatment for major capital projects and certain UFG volume variances;
- Smaller dead-band for earnings sharing; and,

EB-2012-0459

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas commencing January 1, 2014.

BEFORE: Paula Conboy
Presiding Member

Cynthia Chaplin
Member

Emad Elsayed
Member

DECISION WITH REASONS

July 17, 2014

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Plan Components

Enbridge's proposed Custom IR includes a number of factors which are also used in traditional IR. These include an Earnings Sharing Mechanism, a Z Factor, and an off-ramp. Enbridge proposed an additional factor, a Sustainable Efficiency Incentive Mechanism. Each of these will be addressed in this section. Parties also made proposals regarding adjustments for 2013 results for purposes of setting rates going into the Custom IR. The Board will address that issue first.

Adjustments for 2013 Results

Enbridge's 2013 financial results show that the company earned 148 basis points above the return on equity that underpins Enbridge's 2013 Board approved rates (or $31.2 million gross basis inclusive of tax). Intervenors argued that the Board should reduce the 2014 base by the $31.2 million 2013 revenue sufficiency. They submitted that this would result in a more realistic base year starting point for the Custom IR which limits the recovery in rates to the Board approved return. Without the adjustment, intervenors argued, Enbridge would build up significant overearnings over the 5 year plan. The Association of Power Producers of Ontario ("APPrO") claimed that Enbridge's 2013 over earnings imply that the 2013 Board approved revenues and cost projections were conservative in Enbridge's favour. The Building Owners and Managers Association (Toronto) ("BOMA") pointed to the recent Union Gas 2014-2018 IRM Settlement Agreement (EB-2013-0202), in which Union Gas agreed to reduce its 2014 revenue requirement by $4.5 million to compensate for 2013 over earnings.

Enbridge provided explanations for the factors that contributed to the 2013 revenue sufficiency and stated that the sufficiency does not change the forecast risk in the 2014 through 2018 forecasts. In Enbridge's view, these factors were either one-time events or beyond the company's ability to control. In all instances, according to Enbridge, the factors are not indications of expected future revenue sufficiency.

Enbridge also argued that by advocating for a $31.2 million adjustment, the intervenors were essentially inappropriately introducing an earnings sharing mechanism into a cost of service year (which typically does not have an earnings sharing mechanism) and attributing ratepayers with 100% of the benefits.

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Board Findings

The Board does not accept that Enbridge is necessarily starting its custom IR period with a built in revenue sufficiency from 2013. A Custom IR is not set based on a single cost of service year the way Enbridge's prior traditional IR plan was. A Custom IR is based on five-year forecasts of costs. Once set, the company is then required to operate within that envelope for the next 5 years. This proceeding provides a complete look at all the costs for the next 5 years and therefore adjustments for whether the company over- or under-earned in the previous year would not be appropriate. However, the fact that Enbridge has been able to consistently over-earn in every year under its last IR plan will inform the Board's thinking on what is required to operate the business going forward.

Parties noted that Union Gas agreed to a reduction in 2014 to compensate for over-earnings in 2013. However, Union Gas adopted a traditional IR plan, not a Custom IR plan. At the time of Enbridge's 2013 settlement, the parties may have expected that 2013 would be followed by a traditional IR plan. However, the 2013 settlement agreement made no provision for an alternative outcome and did not include an earnings sharing mechanism. The Board subsequently issued its RRFE Report that provided for a Custom IR option. Enbridge used the report as guidance and submitted a Custom IR plan. It would be inappropriate to impose an Earnings Sharing Mechanism for 2013 after the fact.

Earnings Sharing Mechanism ("ESM")

An Earnings Sharing Mechanism ("ESM") is a tool which provides for benefit sharing between ratepayers and shareholders if the company earns more than its allowed return during the IR term. The form of ESM that Enbridge has proposed going forward is similar to that approved in its prior IR plan and includes three components:

- Under-earnings: if the weather normalized return is less than the allowed ROE, the under-earnings will be borne entirely by the shareholders.
- A "dead band": if the weather normalized return is less than 100 basis points above the allowed ROE, then ratepayers receive no benefit and all of the extra earnings flow to the shareholders.
- A sharing ratio above the "dead band": if the weather normalized return is more than 100 basis points above the allowed ROE, the extra earnings will be shared 50:50 between ratepayers and shareholders.

None of the parties disputed that an ESM plan was appropriate. However, views differed as to the operation of the dead band and the sharing ratio.

Board Findings

The Board will establish an ESM for Enbridge's Custom IR. The ESM will provide a performance incentive to Enbridge while at the same time ensuring that ratepayers share in the benefits for that performance.

All parties, including Enbridge, agreed that the "allowed" ROE for purposes of calculating the ESM should be the ROE used to determine the allowed revenue requirement. The Board will adopt this approach because it ensures that the earnings sharing is based on weather normalized actual results compared to what is embedded in rates.

Many parties argued that ratepayers are bearing greater risks under Enbridge's proposed Custom IR plan relative to its prior plan, and that the ESM should be adjusted so that the ratepayers' share of the benefits is larger. The parties argued that the lack of independent third-party cost benchmarking leads to an incentive for Enbridge to over-forecast costs and under-forecast earnings. Intervenors recommended a variety of approaches:

- Energy Probe Research Foundation ("Energy Probe"), with the support of School Energy Coalition ("SEC") and Canadian Manufacturers and Exporters ("CME") proposed that there be no dead band and that the first 100 basis points of over-earnings should accrue entirely to ratepayers while the next 100 basis points of over-earnings should accrue entirely to Enbridge. Any earnings over 200 basis points should be shared 90:10 in favor of ratepayers.
- Consumers Council of Canada ("CCC") proposed the elimination of the dead band and a 50:50 sharing of all of the over-earnings.
- APPrO also recommended a 50:50 sharing of all of the over-earnings for the first 100 basis points, beyond which, the benefits should be shared 90:10 in favour of the ratepayer.

Enbridge argued that changing the parameters of an already asymmetrical ESM further in favour of ratepayers should be balanced against the fact that an IR plan is meant to incent a utility to find and implement sustainable efficiencies. In reply, Enbridge proposed an approach that would still allow the company to retain the first 100 basis points of over-earnings, but then it would share any over-earnings beyond that level on a 90:10 basis in favour of ratepayers.

The Board finds that the dead band should be eliminated and that all over-earnings will be shared 50:50 between ratepayers and shareholders. The Board agrees that the central issue is that the sharing with ratepayers needs to be balanced with an incentive to find and retain efficiencies. The Board also agrees with CCC that a key consideration is the overall IR framework and the other parameters. The Board is approving a Custom IR for Enbridge, but must address the shortcomings of the plan. The lack of total cost benchmarking and the lack of independent budget assessments result in a greater risk that costs have been over-forecast. Therefore, the Board concludes that additional ratepayer protection is warranted. A 100 basis point dead band provides insufficient protection for ratepayers, and therefore the Board finds that the dead band should be eliminated for this Custom IR plan. However, the Board is also concerned that there be suitable performance incentives for Enbridge and finds that a sharing ratio of 90:10 in favour of ratepayers largely eliminates the performance incentive for Enbridge. The Board finds that a sharing ratio of 50:50 provides a suitable incentive level for the company while still ensuring significant benefits for ratepayers. The Board also addresses risk sharing and efficiency levels further in the capital expenditure and O&M expenditure sections of this decision.

Sustainable Efficiency Incentive Mechanism ("SEIM")

Enbridge proposed a Sustainable Efficiency Incentive Mechanism ("SEIM") which it claims will promote long-term sustainable efficiencies within the custom IR framework, including near the end of the IR term. Enbridge explained that IR plans tend to incent short-term cost cutting and discourage the adoption of new productivity measures near the end of the plan term. The SEIM is an attempt to address these issues by providing a financial reward to the company for undertaking sustainable efficiency improvements.

The proposed SEIM has three steps, which would be undertaken within Enbridge's rebasing application for 2019:

- Calculating the potential reward: The potential reward would equal one half of the difference between the average ROE achieved during the IR term and the average ROE allowed during the IR term. The potential reward would form a premium on the ROE that applies to rates for the rebasing year and the following year (2019

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Mr. Shepherd

REF: Tr.2 p18

Please provide the achieved ROE and the allowed ROE for each of the last ten years for each of Union and Enbridge.

Response:

Please see the tables below. Please note that these tables were originally included in the response to OGVG Interrogatory #11 (Exhibit C.OGVG.11) and have been revised to included achieved ROE figures for 2008 to 2017.

EGD Earning Sharing Results

Year	Ratepayer Share of ESM ($Millions)	Gross Normalized Over Earnings (Above Allowed ROE + Threshold) ($Millions)	Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance Proceeding
2008	5.60	11.20	10.21	8.66%	1.00%	50%/50%	EB-2009-0055
2009	19.30	38.60	11.20	8.31%	1.00%	50%/50%	EB-2010-0042
2010	17.35	34.70	11.10	8.37%	1.00%	50%/50%	EB-2011-0008
2011	14.30	28.60	10.38	7.94%	1.00%	50%/50%	EB-2012-0055
2012	7.39	14.80	9.28	7.52%	1.00%	50%/50%	EB-2013-0046
2013	-	31.20	10.41	8.93%	N/A	N/A	No ESM
2014	12.65	25.30	10.46	9.36%	0.00%	50%/50%	EB-2015-0122
2015	6.45	12.90	9.82	9.30%	0.00%	50%/50%	EB-2016-0142
2016	3.40	6.80	9.42	9.19%	0.00%	50%/50%	EB-2017-0102
2017	23.55	47.10	10.27	8.78%	0.00%	50%/50%	Preliminary results

Union Earning Sharing Results

Year	Ratepayer Share of ESM ($Millions)	Gross Over Earnings (Above Allowed ROE + Threshold) ($Millions)	Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance Proceeding
2008	34.17	46.03	13.35%	8.81%	2.00%	90%/10%	EB-2009-0101
2009	7.40	14.79	11.24%	8.47%	2.00%	50%/50%	EB-2010-0039
2010	3.43	6.87	10.91%	8.54%	2.00%	50%/50%	EB-2011-0038
2011	2.54	5.08	10.38%	8.10%	2.00%	50%/50%	EB-2012-0087
2012	15.13	24.97	11.03%	7.67%	2.00%	90%/10%	EB-2013-0109
2013	-	32.20	10.67%	8.93%	N/A	N/A	No ESM
2014	7.42	14.85	10.69%	8.93%	1.00%	50%/50%	EB-2015-0010
2015	-	-	9.89%	8.93%	1.00%	N/A	EB-2016-0118
2016	-	-	9.24%	8.93%	1.00%	N/A	EB-2017-0091
2017	-	-	9.15%	8.93%	1.00%	N/A	Preliminary results

Notes:

(1) Union reports achieved ROE on an actual basis while EGD reports achieved ROE on a weather-normalized basis.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

MAADs Application

Reference: (Ex. B/T1/pp. 9-10)

Question:
At the end of December 2016 EGD had approximately 2,100 employees. At the end of December 2016 Union had approximately 2,300 employees.

a) For both Union and EGD, please provide the number of employees/FTEs in each year 2014-2018.
b) For each year of the deferred rebasing period what is the expected number of employees/FTEs?
c) In 2016 EGD went through a corporate restructuring. How many employees left the company in 2016? What were the savings attributable to that restructuring initiative?
d) Please provide copies of all studies undertaken related to workforce alignment within the new combined utility.

Response

a) Please see the tables below.

Union Headcount Information:

Year	# of Employees
2012	2,216
2013	2,196
2014	2,233
2015	2,283
2016	2,312
2017	2,286
2018*	2,370

*2018 data is as of Feb.28, 2018

EGD Headcount Information:

Year	# of Employees
2012	2,126
2013	2,221
2014	2,204
2015	2,370
2016	2,071
2017	1,942
2018*	1,938

*2018 data is as of Feb.28, 2018

b) Please see the response to BOMA Interogatory#11(a) found at to Exhibit C.BOMA.11.

c) The restructuring in 2016 resulted in the departure of approximately 100 individuals with a savings range of approximately $9 to $10 million.

d) There are no studies.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Consumers Council of Canada ("CCC")

MAADs

Reference: (Ex. B/T1/pp. 9-10)

Question:
At the end of December 2016 EGD had approximately 2,100 employees. At the end of December 2016 Union had approximately 2,300 employees.

a) For both Union and EGD, please provide the number of employees/FTEs in each year 2014-2018.
b) For each year of the deferred rebasing period what is the expected number of employees/FTEs?
c) In 2016 EGD went through a corporate restructuring. How many employees left the company in 2016? What were the savings attributable to that restructuring initiative?
d) Please provide copies of all studies undertaken related to workforce alignment within the new combined utility.

Response

Reported headcount for Union and EGD includes: /u

- Full-time and part-time regular employees; and,
- Full-time and part-time temporary employees.

Reported headcount for Union and EGD excludes: /u

- Contractors;
- Students;
- Seasonal employees;
- Affiliate employees;
- Leave of absences; and,
- Employees on long-term disability.

a) Please see the tables below.

Union Headcount Information:

Year	# of Employees
2012	2,211
2013	2,200
2014	2,233
2015	2,269
2016	2,288
2017	2,271
2018*	2,240

/u

*2018 data is as of Feb.28, 2018. All other years are as of December 31.

EGD Headcount Information:

Year	# of Employees
2012	2,126
2013	2,221
2014	2,204
2015	2,138
2016	2,071
2017	1,942
2018*	1,938

/u

*2018 data is as of Feb.28, 2018. All other years are as of December 31.

b) Please see the response to BOMA Interogatory#11(a) found at to Exhibit C.BOMA.11.

c) The restructuring in 2016 resulted in the departure of approximately 100 individuals with a savings range of approximately $9 to $10 million.

d) There are no studies.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Culbert
To Ms. Girvan

REF: Tr.1, p.154

Please provide the 2018 forecast number of FTEs.

Response:

Please see the table below.

Year	Headcount	Reduction	Headcount Date	Estimated Annual Employee Savings	Gross Annual Severance Costs	Total Impact
2018	1938	-4	Feb month end	(521,924)	127,863	(394,061)
2017	1942	-129	Dec 31st	(16,832,049)	5,030,886	(11,801,163)
2016	2071	-67	Dec 31st	(8,742,227)	18,109,700	9,367,473
2015	2138	-66	Dec 31st	(8,611,746)	15,226,484	6,614,738
2014	2204	N/A	Dec 31st			

Notes:
Assumed average employee compensation = $130,481
Calculation assumes all headcount reductions were executed Jan 1 and had a full year equivalent.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Reinisch
To Mr. Shepherd

REF: Tr.1, p.67

Please provide a list of steps that have already been implemented to rationalize activities between the two utilities.

Response:

The following table outlines changes (if any) that have been implemented to rationalize activities between the two utilities.

Area	**Changes (if any)**
Business Development	No steps have been implemented to rationalize activities between the two utilities.
Customer Care	No steps have been implemented to rationalize activities between the two utilities.
Distribution Operations	No steps have been implemented to rationalize activities between the two utilities.
Engineering	No steps have been implemented to rationalize activities between the two utilities.
Enterprise Safety & Operational Reliability	These functions continue to operate separately. Presently the two utilities continue to work with the enterprise strategy for broader alignment with any charges occurring through the affiliate relationship code as required.
Finance	The finance departments at both Union and EGD are under common leadership. Additionally the accounting and O&M groups are under common leadership. These leaders manage distinct departments that provide respective services to each utility. The costs associated with the centralized leadership position are charged to each of Union Gas and EGD as per affiliate relationship code requirements.
Gas Control	No steps have been implemented to rationalize activities between the two utilities.

Area	Changes (if any)
Human Resources	Leadership of both Union Gas and EGD HR Business Partner function has centralized under one common leader. The costs associated with the centralized position are charged to each of Union Gas and EGD as per affiliate relationship code requirements. None of the two utilities Business Partner teams have been rationalized. The two utilities operate separate HR systems and teams.
Information Technology	Both Union Gas and EGD have separate IT support teams that provided project implementation and application support services. There have not been any steps taken to rationalize these functions given the distinctly different set of software and inherent need for unique skills and knowledge that distinct software necessitates.
Public Affairs	No steps have been implemented to rationalize activities between the two utilities.
Real Estate Services	This is a shared service within the larger enterprise and cost are allocated based on the work for each utility
Regulatory	No steps have been implemented to rationalize activities between the two utilities.
Sales	No steps have been implemented to rationalize activities between the two utilities.
Storage and Transmission	No steps have been implemented to rationalize the regulated storage and transmission activities between the two utilities. The unregulated business in both utilities is rationalizing efforts and all work that occurs is charged directly to the unregulated business.
Supply Chain Management	No steps have been implemented to rationalize activities between the two utilities. Supply Chain groups at both EGD and Union Gas are leveraging common standards and strategies with the larger enterprise.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Undertaking of Mr. Kitchen
To Mr. Shepherd

REF: Tr.1, p.76

Please provide a corporate structure chart for Enbridge Inc.

Response:

The Applicants undertook to provide any corporate organizational charts ("org charts") that are disclosed publicly. The Applicants filed a current and post-amalgamation simplified org charts as part of the Applications at Exhibit B, Tab 1, Attachment 4.

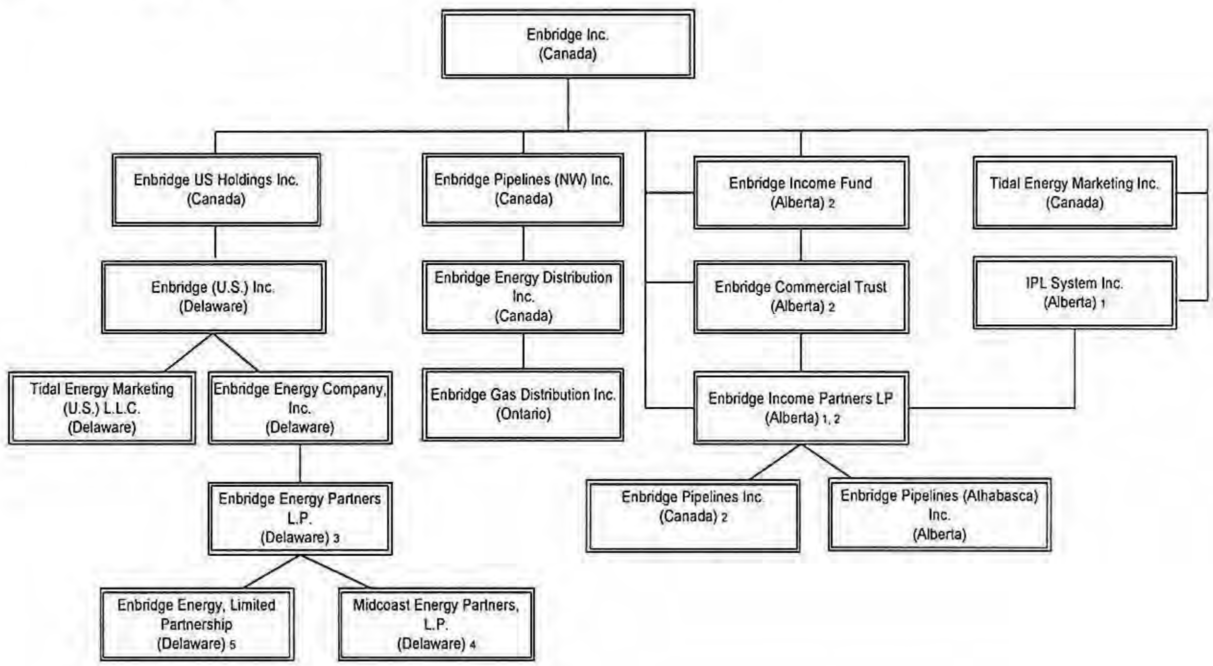
Enbridge Inc. does not disclose full org charts publicly. However, under Canadian securities rules, Enbridge Inc. was required to publicly disclose an org chart showing its material subsidiaries. As such, Enbridge Inc.'s annual information form for the year ended December 31, 2016, at Attachment 1, provides the required org. As of January 1, 2018, Enbridge Inc. became a U.S. domestic issuer subject to U.S. securities disclosure rules, not Canadian rules. The U.S. rules do not require the disclosure of org charts.

Spectra Energy Corp. ("Spectra") did not produce or disclose similar org charts to Enbridge Inc. because it was subject to U.S. securities rules. However, for the special meeting of shareholders held on December 15, 2016 to approve the Spectra merger, Enbridge Inc. under the Canadian rules was required to disclose a chart showing the Spectra structure. This was done on page F-2 of Enbridge Inc.'s proxy circular for the special meeting, at Attachment 2.

Date	Event
December 18, 1992	Articles amended in accordance with the Plan of Arrangement effected on December 18, 1992 between the Company and EPI (formerly Interprovincial Pipe Line Inc.). Pursuant to the Plan of Arrangement, the Company, previously a wholly-owned subsidiary of EPI, became the parent of EPI.
May 5, 1994	Articles amended to (i) change the Company's name from "Interprovincial Pipe Line System Inc." to "IPL Energy Inc.", and (ii) change the place of the registered office of the Company to Calgary, Alberta.
October 7, 1998	Articles amended to change the Company's name from "IPL Energy Inc." to "Enbridge Inc.".
April 29, 1999	Articles amended to (i) divide each then issued and outstanding Common Share on a two for one basis, effective May 10, 1999; and (ii) provide the Board with a process to add directors between meetings of the shareholders.
May 5, 2005	Articles amended to divide each then issued and outstanding Common Share on a two for one basis, effective May 21, 2005.
May 11, 2011	Articles amended to divide each then issued and outstanding Common Share on a two for one basis, effective May 26, 2011.

INTERCORPORATE RELATIONSHIPS

The following organization chart presents the name and the jurisdiction of incorporation of Enbridge's material subsidiaries as at Year End. The chart does not include all of the subsidiaries of Enbridge. The assets and revenues of excluded subsidiaries did not, individually exceed 10%, and in the aggregate exceed 20%, of the total consolidated assets or total consolidated revenues of Enbridge as at Year End. Unless otherwise indicated, the Company owns, directly or indirectly, 100% of the voting securities of all the subsidiaries below.



Notes:

(1) The Company holds all of the Class C units of EIPLP, both directly and indirectly through its ownership interest in IPL System. ECT and EIPGP hold all of the Class A units of EIPLP.

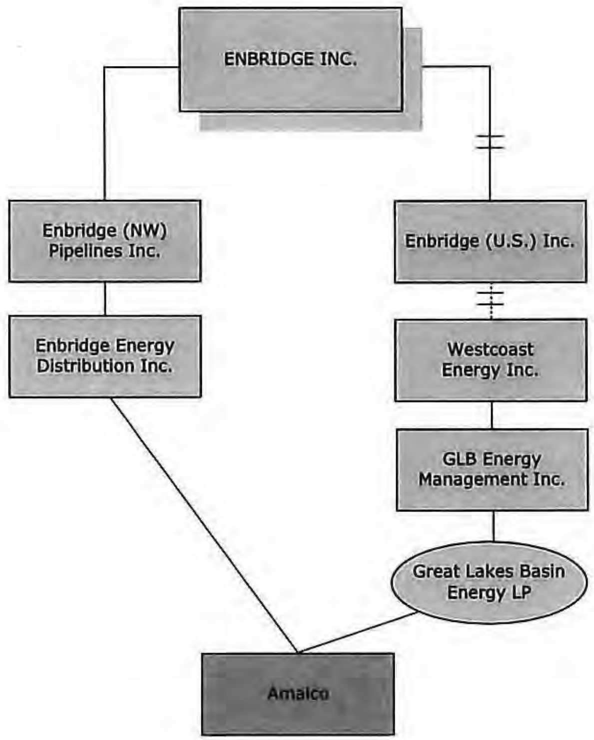
(2) The Company holds a 86.9% economic interest in the Fund Group.

(3) The Company holds a 35.3% economic interest in EEP, held indirectly through its ownership interest in Enbridge Energy Company, Inc. Additionally, Enbridge holds a US$1.2 billion investment in EEP preferred units.

(4) EEP's interest in MEP is held through ownership of a 2% general partner interest through Midcoast Holdings, L.L.C. as well as a 51.9% limited partner interest. On January 27, 2017, Enbridge announced it would acquire all of the outstanding publicly-held common units of MEP. See "United States Sponsored Vehicle Strategy" of this AIF.

(5) EEP's interest in EELP is held through a 0.0005% general partner interest through Enbridge Pipelines (Lakehead) L.LC. as well as a 99.999% limited partnership interest.

Post Amalgamation



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minimal balance will actually exist in the account with required clearance due to the forecast customer amounts being updated annually versus originally forecast).

EGD's Proposal to Adjust Base Rates

The result of the smoothing mechanism is that in 2018 the approved rates will recover revenues of $131.1 million while the approved costs are effectively $126.2 million. EGD will book an entry to credit the deferral account by an amount of $4.9 million such that the income statement recognizes a match between approved revenue and costs.

The approved CIS and customer care cost level for 2018 is $126.2 million (compared to 2018 rates recovering $131.1 million) and therefore, EGD proposes to decrease 2018 rates by $4.9 million. Absent this adjustment, the application of a price cap formula against approved 2018 rates will generate future revenues that would immediately exceed the approved costs in 2018 (i.e. ongoing rates would reflect a timing difference that was specific to the 2013 – 2018 time period).

5. Customer Protection Measures

The Applicants propose a Scorecard to measure and monitor performance over the 10 year deferred rebasing period. The proposed Scorecard is modelled after the electricity distributors' scorecard and includes measures for customer focus, operational effectiveness, public policy responsiveness and financial performance. The Scorecard is provided at Exhibit B, Tab 1, Attachment 2. The Scorecard metrics include a combination of existing metrics, service quality requirements ("SQR") and best practice metrics; and aims to align customer and utility interests, while continuing to achieve public policy objectives and reinforcing fiscal prudence. The categories of measures included in the scorecard are as follows:

Customer Focus: This performance measure is focused on service quality and customer satisfaction. The metrics included in this measure are the Board's customer care related SQRs. These include:

1. Reconnection response time
2. Scheduled appointments met on time
3. Telephone calls answered on time
4. Customer complaint written response
5. Billing accuracy
6. Abandon rate
7. Time to reschedule missed appointments

Operational Effectiveness: This performance measure is focused on safety, system reliability and asset management. The metrics included in this measure include the Board's operations related SQRs and metrics for compression reliability and damages:

8. Meter reading performance
9. Percent of emergency calls responded within one hour
10. Compression reliability
11. Damages

Public Policy Responsiveness: This performance measure includes a metric that addresses natural gas savings achieved through DSM programs:

12. Total cumulative cubic meters of natural gas saved[12]

Financial Performance: This performance measure includes metrics that align with the Applicants' current OEB reporting, through the OEB Yearbook that is published annually. These include:

13. Current ratio
14. Debt ratio
15. Debt to equity ratio
16. Interest coverage
17. Financial statement return on assets
18. Financial statement return on equity

The proposed Scorecard will demonstrate Amalco's continued focus on providing safe and reliable service to customers.

6. Deferral and Variance Accounts

The list of the Applicants' current approved deferral and variance accounts is provided at Exhibit B, Tab 1, Attachment 3. EGD did not request the continuation of its Customer Care Services

[12] Board-approved, following the completion of the DSM audit process and associated Board process.

KT3.4

Impacts of ICM Proposal for Customers

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Totals
Opening Rate Base	0	315	593	753	943	1,233	1,504	1,616	1,910	1,998	
New ICM Capital	323	294	184	219	326	317	165	354	155	101	2,438
Depreciation	8	17	23	29	36	46	53	60	67	71	
Closing Rate Base	315	593	753	943	1,233	1,504	1,616	1,910	1,998	2,028	
Depreciation	8	17	23	29	36	46	53	60	67	71	410
Cost of Capital	13	35	49	60	73	92	107	120	132	136	816
Tax	-2	-2	-2	-1	-3	-4	-3	0	2	5	-10
Total ICM Revenue	18	49	70	87	107	133	157	180	201	212	1,215
Threshold Capital	832	838	839	848	854	859	865	871	878	885	8,570
Total Capital	1,155	1,132	1,023	1,067	1,180	1,176	1,030	1,225	1,033	986	11,008
Board Presentation Page 22											
Maintenance	561	556	568	526	501	587	578	597	607	598	5,679
Attachments	336	289	271	323	353	270	287	274	268	286	2,957
Subtotal Non-ICM	897	845	839	849	854	857	865	871	875	884	8,636
ICM Eligible	323	308	186	224	332	317	171	372	155	152	2,540
Subtotal Customers	1220	1153	1025	1073	1186	1174	1036	1243	1030	1036	11,176
Synergy Investments	11	36	53	37	13						150
Total	1231	1189	1078	1110	1199	1174	1036	1243	1030	1036	11,326

The implementation plans will be staggered to ensure organizational capacity to support and adopt the required changes. The PMO activities will provide oversight to all implementation plans and functions. Based on the preliminary management assessment, the current prioritization of integration programs would be to first optimize the overall management structure, then address the Customer Service opportunities, followed by Distribution Work Management and Asset Management. Other smaller system optimization and process improvements would be integrated into this prioritized plan as organizational capacity allows. With the merger at the parent company level, the integrated utility will continue to support shared service integration activities that commenced in 2017 and will continue into 2020 for various functions including Human Resources, Technical Information Systems, Supply Chain Management, Finance, Public and Government Affairs and Enterprise Safety & Operational Reliability, and Facilities.

Prior to any software or hardware implementation for systems, a review and alignment of work processes will be undertaken related to operating procedures, engineering standards and specifications, asset and operations documentation and records. Additional opportunities for benefits will be identified by working directly with business unit leads and teams as the detailed planning is undertaken. This process will also ensure that perceived benefits are rationalized.
Overview of Estimates for Integration Capital Investments and O&M Savings ($ Millions) over 10 years

Item	Potential Capital Investment		Potential O&M Savings	
	Minimum	Maximum	Minimum	Maximum
Customer Service	$25 M	$110 M	$120 M	$250 M
Distribution Work Management	$10 M	$90 M	$30 M	$150 M
Shared Services	$ 5 M	$20 M	$15 M	$50 M
Storage & Transmission	$5 M	$10 M	$15 M	$50 M
Management Functions & Other	$5 M	$20 M	$170 M	$250 M
Total	$50 M	$250 M	$350 M	$750 M

Note: Estimates are unclassified but indicative of the total opportunities based on prior experience with related system implementations and capital investments, percentages of total operating costs in each category, and a preliminary comparison of practices between the two utilities and industry benchmarking information. The maximum level of opportunities will be challenging to achieve given the capacity of the organization to support multiple initiatives and the upfront time required to plan and implement changes in all of these areas within the 10 year timeframe. Given the preliminary nature of the opportunity assessments, all transition costs not captured in the capital costs are consider net within the savings shown above.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Ontario Energy Board Staff ("Staff")

MAADs Issues List – Issue No. 2

Reference: Exhibit B, Tab 1, p. 5

Preamble: The evidence notes that in accordance with the Consolidation Handbook, the applicants are seeking an Earnings Sharing Mechanism (ESM) consistent with the MAADs policy framework, specifically an ESM for years six through ten of the deferred rebasing period. At the same time, in order to ensure a successful amalgamation, the applicants have chosen to defer rebasing for 10 years. The applicants have also filed a separate rate setting mechanism application (EB- 2017-0307) which proposes an annual index mechanism along with certain non-routine adjustments.

Questions:
If the OEB were to approve a shorter deferred rebasing period of five years for example and an ESM that begins in year one, do the applicants intend to:

a) Proceed with the amalgamation
b) Propose a Price Cap IR methodology to set rates from 2019 to 2024.

Response

The intent of the Board's MAADs framework and policy is to incent efficiencies that ultimately benefit customers. The proposed amalgamation of EGD and Union is a significant undertaking. The degree of integration is highly dependent on the term. The Applicants have selected a term of 10 years in order to make deep, meaningful and lasting improvements. The quantity and complexity of the Information Technology and related process changes required to support efficiencies requires a considerable timeline to allow for investigation, design, costing, implementation and testing such that Amalco is able to continue to provide safe, reliable service to its customers. Amalco will need to make significant upfront investments and requires sufficient time to economically justify the investments and realize the benefits of the efficiencies prior to rebasing.

A term less than 10 years will not provide Amalco sufficient incentive and time to pursue the breadth of the proposed integration activities. The suggested term of five years would likely result in very little integration. Management's own high level estimate of integration project timelines shown in response to BOMA Interrogatory #16 (d) (i), Attachment 1 found at Exhibit

C.BOMA.16 and reproduced below shows that even an aggressive schedule extends integration beyond the five year mark of the 10 year deferred rebasing period. Given the number and size of integration initiatives being undertaken over the 10 year period, the 10 deferred rebasing period is key to achieving the full potential of integration activities in a balanced manner, while delivering quality within a reasonably paced timeline. As such, the amalgamation could not proceed as outlined with a term of five years.

Project Timelines

There are a range of implementation timelines. The moderate to aggressive timeline selected allows for the delivery of benefits over the ten year timeframe

Over the course of the 10 year deferred rebasing period, Amalco is forecasted to achieve on average 20 bps above the forecast allowed Return on Equity (ROE) as shown on slide 23 of the presentation provided in response to FRPO Interrogatory #1, Attachment 1 found at Exhibit C.FRPO.1, and summarized below.

	Proposed Filing: 10 year MAADS (Escalated Price Cap + Incremental Capital Module)									
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Achieved ROE	9.2%	9.5%	9.4%	9.4%	9.4%	9.5%	9.5%	9.7%	9.7%	9.6%
Allowed ROE	9.2%	9.3%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%	9.4%

Included in the forecasted 20 bps are "unidentified efficiencies" as provided in EB-2017-0306 Exhibit B, Tab 1, Attachment 12. These unidentified efficiencies represent additional savings that Amalco will need to find in those specific early years of the 10 year deferred rebasing period so that Amalco will achieve a ROE that approximately equals the forecasted allowed ROE for that year. The unidentified efficiencies were included to recognize that all efficiencies cannot be identified today with precision and Amalco will need to undertake additional efforts and related savings to those estimated in Attachment 12 in order for the utility to achieve that year's forecasted allowed ROE.

In its Rate Handbook at p.28, the Board stated:

> While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred.

The example of an ESM that begins in year one will give Amalco less incentive to achieve the maximum savings for ratepayers upon rebasing while taking on the risk of integration. An ESM needs to ensure no disincentive to pursue productivity savings. As such, the ESM as proposed for Amalco in the last 5 years of the 10 year deferred rebasing period would provide the proper incentive for Amalco while enabling ratepayers to benefit in the event of utility earnings in excess of 300 bps above allowed ROE.

As stated at EB-2017-0306, Exhibit B, Tab 1, pages 14 to 15, the OEB's Decision in this proceeding must be assessed by the board of directors of Enbridge Inc. and the boards of directors of EGD and Union. The boards of directors must ensure that any upfront investments are justified and prudent based on the synergies to be realized over the deferred rebasing period, prior to determining whether to proceed with the amalgamation.