EB-2017-0306/07

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited, pursuant to section 43(1) of the *Ontario Energy Board Act, 1998*, for an order or orders granting leave to amalgamate as of January 1, 2019.

Energy Probe Research Foundation
EB-2017-0306/07
COMPENDIUM PANEL 1

Ontario Energy Board | Commission de l'énergie de l'Ontario | Ontario

EB-2013-0202

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 a multi-year incentive rate mechanism to determine rates for distribution, transmission and storage of gas effective January 1, 2014.

BEFORE: Ken Quesnelle
Presiding Member

Paula Conboy
Board Member

Ellen Fry
Board Member

DECISION AND ORDER
October 7, 2013

Union Gas Limited ("Union") filed an Incentive Rate Mechanism ("IRM") application on July 31, 2013 with the Ontario Energy Board (the "Board") pursuant to section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B. The application is for an order or orders approving a multi-year IRM framework to determine rates for the distribution, transmission and storage of natural gas, effective January 1, 2014. The Board assigned the application File Number EB-2013-0202.

Union's current rates are based on a cost of service model that was approved by the Board in 2012 for rates effective January 1, 2013. In this application, Union has proposed an IRM framework for the period 2014 to 2018. Union's proposed IRM parameters are the product of a comprehensive Settlement Agreement (the "Agreement") between Union and parties that were intervenors in Union's previous rates proceeding. The Agreement was filed as part of Union's application.

The Board issued a Notice of Application and Hearing dated August 14, 2013. In Procedural Order No. 1 issued on September 19, 2013, the Board established the approved list of intervenors for this proceeding. The Board further directed intervenors that were not party to the settlement to file a letter informing the Board of their position on the Agreement.

All intervenors that were not parties to the settlement filed letters supporting or taking no position on the Agreement[1].

In Procedural Order No. 2 issued on September 30, 2013, the Board determined that it would hold a hearing where Union would present the Agreement and respond to any questions or clarifications sought by the Board panel or Board staff.

The hearing was held for that purpose on October 3, 2013. During the presentation of the Agreement, Board staff and the Board panel obtained clarifications from Union on a number of issues. At the end of Union's testimony, Board staff sought Union's position on whether the evidence provided at the hearing formed part of the Agreement. Union replied that it would not characterize its testimony as part of the Agreement but rather as evidence supporting the Agreement and that the Board could rely on it. In response to further questions from Board staff with respect to possible use of the testimony Union accepted that the Board could rely on the testimony in the event that any interpretation disputes arise in the future.

The Board accepts the Agreement, as clarified by the testimony of Union's witnesses at the hearing.

The Board commends Union and the participating stakeholders for their efforts in coming to an agreement that the Board considers to be in the public interest.

[1] Letters were filed by Ontario Greenhouse Vegetable Growers, Enbridge Gas Distribution Inc., Ontario Power Authority, TransCanada Energy Ltd. and Just Energy Ontario L.P.

The Board considers it necessary to make provision for the following matters related to this proceeding. The Board may issue further procedural orders from time to time.

THE BOARD ORDERS THAT:

1. The Board accepts the Settlement Agreement as filed.

2. The intervenors shall file with the Board and forward to Union, their respective cost claims for the proceeding before the Board within 14 days from the date of the Decision and Order.

3. Union shall file with the Board and forward to the intervenors any objections to the claimed costs within 21 days from the date of the Decision and Order.

4. The intervenors shall file with the Board and forward to Union any responses to any objections for cost claims within 28 days of the date of the Decision and Order.

5. Union shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings to the Board must quote the file number, EB-2013-0202, be made through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice , and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at http://www.ontarioenergyboard.ca/OEB/Industry. If the web portal is not available parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

All communications should be directed to the attention of the Board Secretary at the address below, and be received no later than 4:45 p.m. on the required date.

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)

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,

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ONTARIO ENERGY BOARD

FILE NO.: **EB-2012-0459**

VOLUME: **1**

DATE: **February 20, 2014**

BEFORE:

Paula Conboy	**Presiding Member**
Cynthia Chaplin	**Member and Vice-Chair**
Emad Elsayed	**Member**

lots of stuff.

So your comment "Why this approach?" starts with your capital requirements, and I take it that we're all on the same page that the primary driver here of this unusual application is you need -- you are feeling you need to spend a bunch of money on capital projects, more than in the past; is that right?

You said it in the technical conference numerous times.

MR. FISCHER: Yes. Clearly capital requirements is a major driver.

MR. SHEPHERD: Okay. You refer here to the fair return standard. I am going to come back to this in a minute. But you do agree that the fair return standard can be met either from a top-down budget or a bottom-up budget; right?

You said that, as well, in the technical conference, I think.

MR. FISCHER: Yes, I would agree with that.

MR. SHEPHERD: Okay, good. I want to go to the next page now. This talks about the OEB's objectives.

We have already talked about how you embed productivity. We will, I am sure, get back to that in the subsequent panels.

You say you will be challenged to meet the cost forecasts. Why is that?

MR. LISTER: I think what we are referring to there, Mr. Shepherd, is among all of the list of productivity efforts that have been assigned and committed to throughout the body of evidence, there are some that we know are clearly not realistic.

An example would be holding salaries and wages to the growth rate of inflation. We are already have high expectations that the growth rate for benefits costs, for example, will be well in excess of inflation, that outside contractor costs will be well in excess of inflation.

There are other measures that we have taken to constrain the budget, for example, holding the number of full-time employees, or FTEs, constant for budget-setting purposes. We know that that will be a tremendous difficulty over the duration of the term.

MR. SHEPHERD: Sorry. So these OM&A budgets, for example, that you are forecasting over the next five years, they're not realistic budgets?

MR. LISTER: I'm saying a number of measures have been taken, as documented throughout the body of evidence, in this case O&M evidence, that enumerate how EGD approached a way to constrain the budget.

And it necessarily required assumptions that will be very difficult to bear out in actual practice over the course of the term.

MR. SHEPHERD: Well, you just said keeping wage costs to inflation was unrealistic. So all your compensation information in your application, then, is not realistic; is that right?

MR. RYCKMAN: No, I don't believe that is the --

benchmarking at the end of the term.

Our goal is to increase transparency. We want to be held to account. We have said: This is what we need to do, and we will do it and we will lay all to bare for everyone to see each and every year.

MR. SHEPHERD: You are actually proposing periodic reporting but no accountability, right?

MR. LISTER: Well, I think the accountability is there, in that we will arrive at a rebasing application in 2019 and we will be held to account on how well or poorly we operated the business and our forecasts played out.

MR. SHEPHERD: You forecast that you need about, call it, $6 billion over the next five years to meet your -- the fair-return standard, based on a bottom-up approach to budgeting.

You actually expect to earn more than your allowed ROE in every single year, don't you? In fact, you will be required to by EI, won't you?

MR. CULBERT: We will definitely be challenged by EI to try to find a way to increase earnings versus what our projections state.

However, that is no different than any other year. We're always challenged to try to find ways to drive out improvements in earnings. It's not any different this time around.

MR. SHEPHERD: So it appears to me that it is reasonable, then, to conclude that you are not likely to spend the whole $6 billion operating the business, because

We do have a proposal for one of the major elements of our capital spend which, again, the Board has dealt with in the LTC for the GTA, which is we proposed a variance account around that project, given the significant nature of the project, that we would only recover the actual amount of revenue requirement that ensues.

MR. SHEPHERD: Under the Union plan, their extra capital funding is also subject to a variance account, so it is trued up at the end; right?

MR. CULBERT: From my understanding, yes.

MR. SHEPHERD: That is not true of your forecast?

MR. CULBERT: No. Like I said, if we were to underspend, the implications of that would be handled in actuals and earnings sharing throughout the term and upon rebasing.

MR. SHEPHERD: How is it handled upon rebasing? Can the Board go back and say, Wait a second, you didn't spend all of that money; give it back?

MR. CULBERT: No. What we're saying is, upon rebasing, our rate base would go to whatever level it is commensurate with spending and rates would be adjusted going forward.

So to the extent there is an overearnings implication from it, it happens inside the ESM proceeding.

MR. SHEPHERD: So, for example, you could spend less on capital during the five years than your budget that you presented to this Board. You could spend less, and as long as you keep that within 100 basis points, it all goes to of what has occurred based on our challenges we're talking about here.

We don't think we're going to get beyond 100 basis points above an ROE. We think we're going to be challenged to meet the ROEs that we have included inside of these projections.

But certainly if the numbers were inside of a range of 300 basis points, we would have to explain what they came about from, and if we were unable to do so...

MR. SHEPHERD: There would be no consequences.

MR. CULBERT: Well, our proposal is that we will be able to show that we do things that get us to -- if we can get to 300 basis points, we will be able to show those things.

MR. SHEPHERD: The other thing you are including which is not in the Union deal is the SEIM, which is basically sort of another way of sharing earnings, right?

It's saying: Well, if we're over-earning, then subject to a bunch of conditions, show that we're over-earning because we're being efficient, that we get more, a bigger share of that, than we would otherwise have gotten; isn't that right?

MR. LISTER: Not exactly. What it would do is give us the right to apply and to justify that there is greater ratepayer benefit than there is long-term shareholder value, so...

And other conditions as well, such as our SQR performance didn't degrade our performance metrics.

would be dealt with during your IRM? If you wanted to offer a new rate, for example, or you wanted to restructure a rate, have you made a proposal for how that should be dealt with in your plan?

MR. RYCKMAN: It is the same as it was in the first gen. So we would come before the Board for approval for that.

MR. SHEPHERD: So it's the same as Union, then?

MR. RYCKMAN: Correct.

MR. SHEPHERD: Okay.

MR. RYCKMAN: Based on my understanding.

MR. SHEPHERD: And there is just two others. On page 33, Union has agreed that if they have service charges that are not energy related -- you have a number of service charges that are not energy related, as well -- that you have to -- they have to come to the Board, but they're not part of the price cap. They're not part of the formula.

The same with you; right? If you wanted to change your various miscellaneous charges, you can, but you have to come to the Board for approval and they're not part of your proposal generally?

MR. CULBERT: That's correct. I think we had one occurrence of that during our first gen IR term, but we're proposing the same process.

MR. LISTER: Again, that is the same as our first generation plan, as well.

MR. SHEPHERD: Exactly.

Finally, on page 34, this deals with rebasing in 2019.

And if I understand what you are proposing, it is essentially the same as Union. You are agreeing that you will file -- regardless of whether you are rebasing, you will file a full cost of service application in 2019?

MR. CULBERT: That's correct.

MR. SHEPHERD: To the best of your knowledge, have I missed any of the other factors in this comparison between the two? Have we caught everything, or does something jump out at you, put it that way? I can't think of anything.

MR. CULBERT: Not at this time. If I do, I will certainly bring it to your attention.

MR. SHEPHERD: Thank you. Madam Chair, I think I have -- I think I have three minutes, but I don't need them. I'm sorry.

MS. CONBOY: Okay, thank you very much. And you have led by good example by coming in under budget in your time.

[Laughter]

MS. CONBOY: No pressure, Ms. Sebalj, but you are next and I have you down for 30 minutes. So if you want to take us to the break, that would be great.

And if I am correct, I've got Mr. Quinn up after Board Staff and Mr. Brett after Mr. Quinn. Is that correct, Mr. Brett?

MR. BRETT: Yes. I hadn't heard that yet, but that's fine.

[Laughter]

MS. CONBOY: Okay. Well, then if you both could also have a look at the cross-examination that has been done to

The Board would -- in that sort of a program, they expect to see savings calculated, right? And documented and then carried forward; is that fair?

MR. RYCKMAN: I believe that is the expectation of not just the Board, but other parties as well, that there will be some sightline to the productivity through the IR term. It certainly came up in the 2013 case. And as you may recall, through that process it was determined that we were productive, but the reporting that we had done, or the lack of reporting, was a concern for some parties, and we committed to do productivity reporting that we'll bring forward to the Board every year through the ESM proceedings.

So I would agree with you it is important to have a sightline to those things, and rebasing would be an appropriate time to bring up issues around productivity over the IR term as well.

MR. BRETT: Now, I just want to summarize. I am going to go into each of these items separately, but I -- other than the SEIM, which I am finished with. We have had enough on SEIM, I think.

But basically, your proposal in your 40-page summary which you are responsible for, is that you are generating savings in four ways.

One is through SEIM, one is through the ESM, one is through -- are savings that you say are embedded in your capital budget, your forecast capital budget, and the fourth is savings which you say are embedded in your

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0459

VOLUME: 2

DATE: February 21, 2014

BEFORE:	Paula Conboy	Presiding Member
	Cynthia Chaplin	Member and Vice-Chair
	Emad Elsayed	Member

MR. JANIGAN: So the clawing back refers to the resetting rates lower after the IR period to costs, isn't that correct, whenever that term "clawing back" is used?

MR. LISTER: That's correct. So a stream of benefits would ensue an investment, and the utility wouldn't be afforded the opportunity to benefit from the full stream of benefits. So they would be effectively rebased or clawed back at rebasing.

MR. JANIGAN: Okay. So, in effect, in putting in this plan at a materially higher level, you are effectively clawing back some benefits from ratepayers that should accrue to those ratepayers?

[Witness panel confers]

MR. LISTER: So if I understood the question correctly, our position is very much that this mechanism is intended to directly respond to the Board's objective of having utilities generate long-term sustainable efficiencies.

So our view is that if we can show to the Board and to stakeholders that we have indeed accomplished that, that the utility should stand to receive some benefit, yes.

MR. JANIGAN: Okay. So let's assume that your 2014 and '18 plan ends and you rebase in 2009 on your building block basis and apply for a multi-year IRM plan for 2020 using the building block approach that largely ignores the 2009 rebased requirement.

How can there be sustained benefits for ratepayers?

MR. LISTER: Well, our view in our presentation of the

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ONTARIO ENERGY BOARD

FILE NO.:	**EB-2012-0459**

VOLUME:	**5**	
DATE:	**February 27, 2014**	
BEFORE:	**Paula Conboy**	**Presiding Member**
	Cynthia Chaplin	**Member and Vice-Chair**
	Emad Elsayed	**Member**

MS. LAWLER: Yes.

MR. SHEPHERD: You're also pretty sure that you are going to be able to meet your budgets?

MS. LAWLER: I don't think we said that.

MR. SHEPHERD: Oh, no? Okay. So do you think you're going to be able to meet your budgets or not?

MR. SANDERS: We do believe we will be able to meet our budgets. The challenge that we have is that in doing that, we are going to have to find a number of productivity improvements along the way.

We have not discovered what all of those productivity improvements are going to be at this point in time.

We have a challenge to identify what those are going to be, and work on them over the IR term to achieve the budgets. We are aware of that.

MR. SHEPHERD: Some of the variable costs which are not in your budget will have to be spent. But the converse is that some of the costs that are in your budget, that you are saying: Here's a reasonable budget for us to spend, those will actually not have to be spent, right? Some of them?

MR. SANDERS: I'm not aware of any of the items in our budget that we would not need to spend.

Again, the process we went through was to identify the things that we did not need to spend during the IR term.

There will be changing circumstances. Again, I can't predict the future precisely for the next five years and exactly what is going to occur. So there will be

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ONTARIO ENERGY BOARD

FILE NO.: EB-2012-0459

VOLUME: 7

DATE: March 3, 2014

BEFORE:

BEFORE:	Paula Conboy	Presiding Member
	Cynthia Chaplin	Member and Vice-Chair
	Emad Elsayed	Member

pressures are more than your budget. So you said, for example, that even though you have numbers here for salaries and wages, in fact, you expect them to -- the normal amount you would expect them to go up is 3 percent per year, right?

MR. KANCHARLA: That's correct, for salaries and wages.

MR. SHEPHERD: And similarly with respect to the second line, "benefits", that you would expect those to go up, and you actually expect those to go up by 6.1 percent per year, right?

MS. TROZZI: That's correct.

MR. SHEPHERD: So then why aren't those the numbers in your budget?

MS. TROZZI: We've chosen to hold the budgets, you know, at the 2 percent level, understanding that we are going to have some challenges. We do know that benefits and salary and wages are potentially going to be an issue. We're hoping to find the savings through some productivity initiatives across the organization. So we know it will be tough, but that's a decision that we made and we're going to need to stick by that.

MR. SHEPHERD: So, in fact, when you say -- for example, you say in 2018 you expect to spend 28.6 million in -- for benefits, that's not actually correct? If you take 6.1 percent, you actually expect to spend $34 million that year, right?

MS. TROZZI: Yes.

	1st Generation Plan	2nd Generation Plan	Rationale for Change in 2nd Generation IR Plan
Annual Rate-Setting Process	In advance of each year, Enbridge provided forecasts of customer numbers and inflation which were used to set an updated Revenue Requirement. Enbridge also provided forecasts of volumes and gas costs and the updated volumes information was applied to the updated Revenue Requirement for that year, to derive final rates.	In advance of each year, Enbridge will provide updated forecasts of volumes (using updated customer forecasts and applying the existing methodologies for HDDs, average use and large volume forecasts) and gas costs. The updated data will be applied to the approved Allowed Revenue for each year to derive final rates for that year.	Minor change to the annual process: while the forecast volumes, pass-through items and rates will be updated each year, the annual rate-setting process will no longer involve formulaic adjustments to the overall Revenue Requirement.
Earnings Sharing	To share earnings more than 100 basis points above Allowed ROE between ratepayers and the Company.	To share earnings more than 100 basis points above Allowed ROE between ratepayers and the Company.	No change.
Z Factor	To protect against unexpected costs or savings outside of management control that have a revenue requirement impact of more than $1.5 million.	To protect against unexpected costs or savings outside of management control that have a revenue requirement impact of more than $1.5 million.	Minor change: proposed improvements to the wording of the Z-Factor criteria.
Off-Ramp	Review of IR Plan if there is a variance from Allowed ROE of 300 basis points or more in either direction.	Review of IR Plan if there is a variance from Allowed ROE of 300 basis points or more in either direction.	No change.
Performance Measurement	Regular reporting through ESM proceedings and RRR filings.	Enbridge will track productivity initiatives and report annually. Enbridge will also track operational performance throughout, and report on performance at the end of the IR term. The Sustainable Efficiency Incentive Mechanism (SEIM) will provide an incentive for sustainable productivity.	Change: The enhanced tracking and reporting of operational performance, and the new tracking and reporting on productivity initiatives will enhance the Board's and stakeholders' understanding of the Company's performance under IR. The SEIM will provide an incentive for further lasting efficiency savings.
Term of Plan	Five Years	Five Years	No change.
Rebasing Requirements	File cost of service information for the first rate proceeding at the end of the IR term.	File cost of service information for the first rate proceeding at the end of the IR term	No change.

Operating and Maintenance Costs

Operating and Maintenance (O&M) costs are the day-to-day costs of running the business. Like capital expenditures, Enbridge's Custom IR plan is built on a 5-year forecast of O&M expenditures. The following table provides the 2013 Board approved and actual, and 2014 to2018 forecast for the main O&M cost categories.

Operating & Maintenance Costs by Category
($ millions)

	2013 Board Approved	2013 Actual	2014	2015	2016	2017	2018
Customer Care/CIS	89.4	83.1	92.6	96.5	100.4	104.4	108.5
DSM	31.6	31.6	32.2	32.8	33.5	34.2	34.9
Pension & OPEB	42.8	44.0	37.2	33.8	30.9	28.5	26.2
RCAM	32.1	32.1	35.3	34.0	33.8	34.8	35.9
Sub-total	**195.9**	**190.8**	**197.3**	**197.1**	**198.6**	**201.9**	**205.5**
Other O&M	**219.2**	**224.7**	**228.0**	**231.5**	**241.0**	**248.5**	**256.3**
TOTAL	**415.1**	**415.5**	**425.3**	**428.5**	**439.5**	**450.5**	**461.8**

The first three rows of the table relate to expenses for Customer Care and Customer Information System (CIS) service charges, Demand Side Management (DSM) expenses and Pension and Other Post-Employment Benefits ("OPEB") expenses. Each of these have been, or will be, set outside of the current case:

- Customer Care/CIS service charges are subject to an approved settlement agreement (EB-2011-0226) which provides a mechanism to determine the costs for each year 2013 to 2018.

**Other O&M Costs
Proposed and Approved
($ millions)**

	2014	2015	2016	2017	2018
Other O&M Proposed	228.0	231.5	241.0	248.5	256.3
Other O&M Approved 1%	228.0	230.3	232.6	234.9	237.3

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Energy Probe Research Foundation ("EP")

MAADs Application

Reference: Exhibit B, Tab 1, Attachment 12

Preamble: This exhibit shows integration costs and savings in Capital and O&M. Energy Probe would like to understand the baseline 2018 costs for each utility and the and outlook in the following O&M Cost categories:

Question:
Corporate Services

a). How much does Union pay to Enbridge Inc (directly or indirectly) in 2018? How will that change in 2019, 2020 and 2021

b). How much does EGD pay to Enbridge Inc in 2018? Please provide both the RCAM and total amounts. How will that change in 2019, 2020 and 2021?

Shared Services

c). Have the applicants prepared an affiliate shared services agreement for 2019? If so please file a copy.

d). Please provide a copy of the plan for shared services. Include the basis for the $4 million capital in 2019 and the savings in 2020.

e). Have Enbridge and Union applied to the Regie d'Energie for approval of the change in ownership and changes to the affiliate relationships and shared services arrangements with Gazifere? If so please provide a Copy of that Application.

f). If not, please indicate when this will be filed and undertake to provide a copy for this proceeding.

Response

a) As per Union's 2018 Budget, net affiliate expenses (including Enbridge Inc.) are $6.7 million.

b) The amount EGD is being charged (CAM) by other affiliates (including Enbridge Inc.) is $60.3 million in 2018.

The amount EGD is being charged (RCAM) by other affiliates (including Enbridge Inc.) is $58.4 million in 2018.

c) The Applicants have not prepared intercorporate services agreements for 2019, only for the current period to the end of 2018.

d) Please see the response to BOMA Interrogatory #16(d) part (i) found at Exhibit C.BOMA.16

e- f) There is no need for the Applicants or Gazifère to apply to the Regie for approvals related to the Applications. EGD does not own Gazifère. EGD is a sister company of Gazifère and intends to continue to provide certain intercorporate services to Gazifère post-amalgamation as Amalco.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

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

MAADs Application

Reference: (Ex. B/T1/p. 33)

Question:
Union has always purchased services from its parent. EGD has always purchased services from its parent. For each year 2013-2018 please provide a detailed list of all services purchased from the relevant parent company, and the associated costs. Please include forecast and actual numbers in each year.

Response

For EGD 2013 to 2017 Regulatory Cost Allocation Methodology (RCAM) amounts, please see below. For 2018, there is a placeholder in the EGD budget of $50.2 million. The EGD 2018 services and allocations have not been finalized.

For Union 2013 to 2018 information, please see below. Union's information contains both affiliate revenues and expenses as Union has historically provided and received corporate services to/from Spectra. Note that 2017 figures are preliminary.

EGD Information:

	Services / Direct Charges	2013	2014	2015	2016	2017
Primary Services	1. Aerial Pipeline Surveillance	$ -		$ -	$ -	$ -
	2. Audit & Accounting Advice	$ 158,418	$ 134,343		$ 189,792	$ 135,038
	3. Board of Directors Support	$ 848,267	$ 707,990	$ 678,780	$ 421,563	$ 360,500
	4. Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ 17,749
	5. Business Development	$ 751,127	$ 303,345	$ 345,025	$ 370,370	$ 476,479
	6. Capital Market Financing & Access	$ 1,029,508	$ 745,805	$ 662,464	$ 735,076	$ 645,059
	7. Cash Management & Banking	$ 997,480	$ 249,517	$ 421,457	$ 328,818	$ 382,995
	8. Enterprise System Program and Project Management	$ -	$ 1,611,719	$ 2,272,174	$ 1,571,338	$ 2,908,463
	9. Corporate Compliance	$ 290,362	$ 201,541	$ 113,441	$ 102,774	$ 92,342
	10. Brand Strategy & Community Investment Relations		$ 247,559	$ 454,520	$ 619,686	$ 262,787
	11. Emerging Energy Technology Research	$ -	$ -	$ -	$ -	$ -
	12. Employee Development	$ 1,318,597	$ 1,140,897	$ 920,683	$ 980,858	$ 1,417,088
	13. Enterprise Infrastructure Program and Project Management	$ -	$ 86,548	$ 4,184,303	$ 6,145,826	$ 4,403,816
	14. Enterprise IT Strategy Planning & Management - inactive	$ -	$ -	$ -	$ -	$ -
	15. Enterprise Infrastructure Management and Technical Support	$ -	$ -	$ 4,535,353	$ 5,392,852	$ 3,910,414
	16. External Audit Coordination	$ 207,076	$ 103,364	$ 52,843	$ 75,193	$ 67,875
	17. External Communications	$ -		$ -	$ -	$ 29,790
	18. Enterprise System Management and Technical Support	$ -	$ 4,902,304	$ 4,077,266	$ 4,157,578	$ 5,090,420
	19. Gas Accounting	$ -	$ -	$ -	$ -	$ -
	20. Gas Contract Administration	$ -	$ -	$ -	$ -	$ -
	21. Gas Supply, Storage, and Transportation Strategy	$ -	$ -	$ -	$ -	$ -
	22. Government Relations & CSR	$ -	$ 268,319	$ 40,320	$ 424,800	$ 304,587
	23. IT Planning and Governance	$ -	$ 1,718,004	$ 2,618,292	$ 3,219,852	$ 3,887,742
	24. Human Resource Advice	$ 171,633	$ 312,301	$ 765,909	$ 1,193,129	$ 608,802
	25. Safety and Process Safety	$ -	$ -	$ 589,472	$ 823,684	$ 879,525
	26. Insurance Claims Support, Strategy and Management	$ -	$ 199,281	$ 167,818	$ 255,577	$ 223,627
	27. Internal Employee Communications	$ -	$ -	$ -	$ -	$ 55,591
	28. Investor Services	$ 1,099,448	$ 1,014,165	$ 744,885	$ 864,332	$ 872,903
	29. Employee Relations Strategy	$ 252,118	$ -	$ -	$ 18	$ 148
	30. Legal Advice	$ 465,382	$ 487,544	$ 501,353	$ 196,076	$ 258,938
	31. Pension Plan Asset Management and Administration	$ -	$ -	$ -	$ -	$ -
	32. Planning, Management & Execution of Internal Audits	$ 243,067	$ 359,369	$ 346,070	$ 247,643	$ 192,759
	33. Rate Regulated Entity Support	$ 225,727	$ 209,479	$ 127,225	$ 42,861	$ 23,477
	34. Records and Information Management	$ 888,504	$ 1,054,087	$ 1,178,672	$ 2,299,041	$ 1,248,733
	35. Reservoir Engineering	$ -	$ -	$ -	$ -	$ -
	36. Risk Assessment and Management	$ 865,435	$ 654,230	$ 1,335,271	$ 479,639	$ 827,579
	37. Strategic Planning	$ 253,073	$ 223,115	$ 504,582	$ 913,595	$ 566,690
	38. Supply Chain Management	$ 46,900	$ 53,482	$ 73,828	$ 159,435	$ 139,631
	39. Tax Advice	$ -	$ -	$ -	$ -	$ -
	40. Tax Reporting & Planning	$ 131,679	$ 70,384	$ 468,068	$ 63,781	$ 67,392

Primary Services	41. Total Compensation and Benefits	$ 2,399,292	$ 1,908,125	$ 1,980,365	$ 1,766,358	$ 1,943,963
	42. Labour Relations	$ 336,424	$ -	$ -	$ -	$ -
	43. MY HR Services	$ -	$ -	$ -	$ 2,155,117	$ 2,859,902
	Accounting Advice	$ -	$ -	$ 154,055	$ -	$ -
	Human Resource Services	$ -	$ -	$ 2,603,972	$ -	$ -
	Consolidation and Planning System Technical Support (Khalix)	$ 275,164	$ -	$ -	$ -	$ -
	Industry Relations & Corporate Social Responsibility (CSR)	$ 415,918	$ -	$ -	$ -	$ -
	Enterprise IT Program Management	$ 661,348	$ -	$ -	$ -	$ -
	Enterprise IT Strategy Planning & Management	$ 236,125	$ -	$ -	$ -	$ -
	Expense System Management & Technical Support (Nacho Navigator)	$ 240,347	$ -	$ -	$ -	$ -
	Financial and Project Accounting System Technical Support (Oracle)	$ 517,170	$ -	$ -	$ -	$ -
	Government Relations	$ 48,971	$ -	$ -	$ -	$ -
	HRIS Management and Technical Support	$ 3,487,053	$ -	$ -	$ -	$ -
	Employee and Labour Relations	$ -	$ 481,772	$ -	$ -	$ -
	Insurance Strategy and Management	$ 325,570	$ -	$ -	$ -	$ -
	Portal Suite Operations & Technical Support	$ 301,334	$ -	$ -	$ -	$ -
	Total Service Charges	**$ 19,488,516**	**$ 19,448,587**	**$ 32,918,466**	**$ 36,196,662**	**$ 35,162,806**
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (2,129,052)	$ (5,000,103)	$ (6,152,935)	$ (6,152,935)	$ (6,152,935)
	Directors Fees & Expenses	$ 1,089,370	$ 1,223,750	$ 1,076,870	$ 1,010,389	$ 682,776
	Depreciation - Risk Management System	$ -	$ 25,132	$ 214,307	$ 173,948	$ 237,081
	Depreciation - Enterprise Systems	$ -	$ 3,392,008	$ 4,091,402	$ 3,900,377	$ 5,096,089
	Insurance Premiums	$ 5,652,239	$ 4,630,857	$ 4,897,830	$ 4,862,895	$ 4,190,719
	Audit Fees	$ -	$ -	$ -	$ -	$ -
	EGD Stock Based Compensation Charge	$ -	$ -	$ 9,636,747	$ 8,750,765	$ 10,219,256
	Risk Management System	$ 133,581	$ -	$ -	$ -	$ -
	BU Stock Based Compensation Charge	$ 10,657,647	$ 9,225,003	$ -	$ -	$ -
	Total Direct Charges	**$ 16,403,765**	**$ 13,696,647**	**$ 13,764,221**	**$ 12,545,440**	**$ 14,272,986**
	Rate of Return	**$ 353,189**	**$ 471,684**	**$ 326,905**	**$ 324,626**	**$ 134,828**
	Total EGD Allocation	**$ 36,245,490**	**$ 33,616,917**	**$ 47,009,692**	**$ 49,066,728**	**$ 49,570,620**

Union Information:

Union Gas Limited
Affiliate Revenue
($000's)

Line No.	Functional Service	2013 Board-approved (a)	2013 Actuals (b)	2014 Actuals (c)	2015 Actuals (d)	2016 Actuals (e)	2017 Actuals (f)	2018 Forecast (g)
1	Bus Devel, S&T	728	506	383	550	427	354	
2	Corp Services	-	-	-	-	-	-	
3	Engineering & Construction	485	178	229	40	35	43	
4	EHS	821	702	912	523	624	453	307
5	Ethics	-	-	-	-	-	-	
6	Finance	1,951	1,881	2,434	2,942	3,348	3,600	2,030
7	Gov Relations	701	627	379	404	348	48	
8	HR	2,480	2,782	2,694	2,927	2,806	2,790	2,967
9	Insurance	150	118	80	68	75	29	
10	IT	4,339	5,509	5,670	6,091	5,810	6,191	5,735
11	Legal	13	5	2	1	66	291	141
12	Other	14	8	4	10	7	64	
13	Public Affairs	-	-	-	-	-	-	
14	Supply Chain	801	772	764	906	963	672	175
15	Tax	1,224	1,166	1,068	992	968	839	
16	Audit	-	-	-	-	429	470	
17	Total	13,706	14,254	14,619	15,454	15,905	15,842	11,355

Union Gas Limited
Affiliate Expenses
($000's)

Line No	Functional Service	2013 Board-approved	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals	2018 Forecast
1	Bus Devel, S&T	206	(65)	-	-	-	-	
2	Corp Services	68	109	109	81	70	91	528
3	Engineering & Construction	437	56	-	-	-	-	
4	EHS	1,097	831	922	701	640	714	450
5	Ethics	230	376	280	424	342	330	
6	Finance	1,286	1,349	1,843	2,158	2,898	2,782	5,864
7	Gov Relations	-	-	-	-	-	-	
8	HR	2,207	1,588	1,825	1,887	1,809	2,056	12,054
9	Insurance	505	97	127	310	302	217	
10	IT	1,729	5,046	5,403	7,945	8,741	8,395	9,613
11	Legal	156	73	155	204	218	213	2,075
12	Other	315	-	-	-	-	1,982	1,691
13	Pub Affairs	5	3	3	20	-	-	1,897
14	Supply Chain	752	889	1,768	3,218	3,772	3,483	792
15	Tax	450	455	435	475	481	472	
16	Audit	-	-	-	-	583	434	
17	Sub Total	9,443	10,807	12,870	17,423	19,856	21,170	34,963
18	Depreciation	2,445	2,052	2,208	2,526	2,152	1,440	9,480
19	Corporate Adjustments							* - 26,300
20	Total	11,888	12,859	15,078	19,949	22,008	22,610	18,143

* Corporate provided Union with an adjustment to bring Union back to 2018 approved budget

Filed: 2018-04-05
EB-2017-0306/EB-2017-0307
Exhibit JT1.17
Page 1 of 1

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.

Filed: 2017-05-09, EB-20167-0102, Exhibit D, Tab 3, Schedule 1, Page 7 of 11
Filed: 2018-04-12, EB-2017-0306/EB-2017-0307, Exhibit C.CCC.6, Attachment 3, Page 7 of 11
Witness: L. Stickles

O&M and Capital Embedded Productivity Results

1.	O&M: Merit increase	(2.5)	(0.5)
2.	O&M: Employee Benefits	(2.3)	(1.1)
3.	O&M: Incremental cost to service new customers	(1.7)	0.1
4.	O&M: Incremental safety and integrity work	(9.3)	(2.6)
5.	O&M: External contractor rate increases	(1.7)	(0.4)
6.	O&M: Increased volume of locates-compliance with Bill 8	(3.8)	(3.0)
7.	O&M: FTEs	(8.7)	(15.0)
8.	O&M: Bad Debt expenses	(5.6)	(8.1)
9.	Total Estimated O&M Reductions	(35.6)	(30.5)
10.	Capital: Customer Attachments	(24.4)	(17.7)
11.	Capital: Departmental Labour	(2.7)	(11.6)
12.	Total Estimated Capital Reductions	(27.1)	(29.3)
13.	Total Estimated Embedded O&M & Capital Reductions	(62.7)	(59.8)

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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.

Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

Handbook to Electricity Distributor and Transmitter Consolidations

January 19, 2016

appear to be significant differences in the size or demographics of consolidating distributors. A key expectation of the RRFE is continuous improvement in productivity and cost performance by distributors. The OEB's review of underlying cost structures supports the OEB's role in regulating price for the protection of consumers.

Consistent with recent decisions,[3] the OEB will not consider temporary rate decreases proposed by applicants, and other such temporary provisions, to be demonstrative of "no harm" as they are not supported by, or reflective of the underlying cost structures of the entities involved and may not be sustainable or beneficial in the long term. In reviewing a transaction the OEB must consider the long term effect of the consolidation on customers and the financial sustainability of the sector.

To demonstrate "no harm", applicants must show that there is a reasonable expectation based on underlying cost structures that the costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been. While the rate implications to all customers will be considered, for an acquisition, the primary consideration will be the expected impact on customers of the acquired utility.

Adequacy, reliability and quality of electricity service

In considering the impact of a proposed transaction on the quality and reliability of electricity service, and whether the "no harm" test has been met, the OEB will be informed by the metrics provided by the distributor in its annual reporting to the OEB and published in its annual scorecard.

The OEB's *Report of the Board: Electricity Distribution Systems Reliability Measures and Expectations*, issued on August 25, 2015 sets out the OEB's expectations on the level of reliability performance by distributors. In the Report, the OEB noted that continuous improvement will be demonstrated by a distributor's ability to deliver improved reliability performance without an increase in costs, or to maintain the same level of performance at a reduced cost.

Under the OEB's regulatory framework, utilities are expected to deliver continuous improvement for both reliability and service quality performance to benefit customers. This continuous improvement is expected to continue after a consolidation and will continue to be monitored for the consolidated entity under the same established requirements.

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[3] Hydro One Inc./Norfolk Power Distribution Inc. – OEB File No. EB-2013-0196/EB-2013-0187/EB-2013-0198
Hydro One Inc./Haldimand County Hydro Inc. – OEB File No. EB-2014-0244

Appendix A: Capital Investment and High Level Estimated O&M Savings for Utility Integration

Integration Capital investment and O&M Savings Schedule ($ Millions)

Item	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Capex											
Customer Care		$ 2	$ 22	$ 32	$ 8	$ -	$ -	$ -	$ -	$ -	$ 65
Distribution work management	$ 7	$ 21	$ 21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 50
Utility Shared Services	$ 4	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13
Storage & transmission	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
Other functions	$ -	$ -	$ 5	$ 5	$ 5	$ -	$ -	$ -	$ -	$ -	$ 14
Sub-Total Costs	$ 11	$ 36	$ 53	$ 37	$ 13	$ -	$ -	$ -	$ -	$ -	$ 150
O&M savings											
Customer Care	$ -	$ 15	$ 15	$ 16	$ 16	$ 26	$ 26	$ 26	$ 26	$ 26	$ 192
Distribution work management	$ -	$ -	$ 11	$ 11	$ 11	$ 16	$ 16	$ 16	$ 16	$ 16	$ 113
Utility Shared Services		$ 2	$ 2	$ 3	$ 3	$ 5	$ 5	$ 5	$ 5	$ 5	$ 35
Storage & transmission	$ -	$ 1	$ 3	$ 3	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 30
Management	$ -	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 180
Other functions						$ 14	$ 14	$ 14	$ 14	$ 14	$ 70
Sub-Total Savings	$ -	$ 38	$ 51	$ 53	$ 53	$ 85	$ 85	$ 85	$ 85	$ 85	$ 620
Additional unidentified efficiencies	$ 3	$ -	$ 12	$ 17	$ 28	$ -	$ -	$ -	$ -	$ -	$ 60
Sub-Total Savings	$ 3	$ 38	$ 63	$ 70	$ 81	$ 85	$ 85	$ 85	$ 85	$ 85	$ 680

Integration Opportunities

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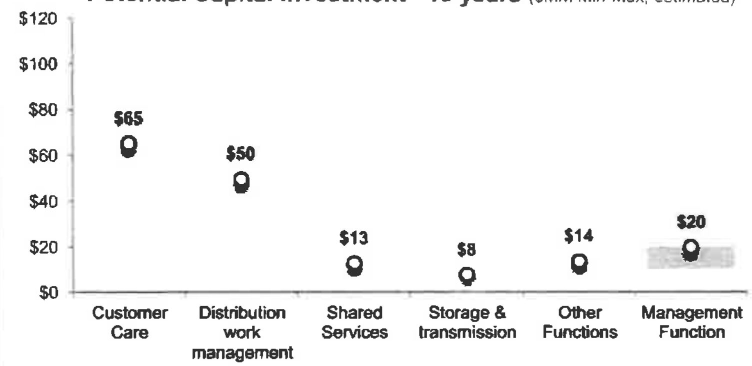
Management Function

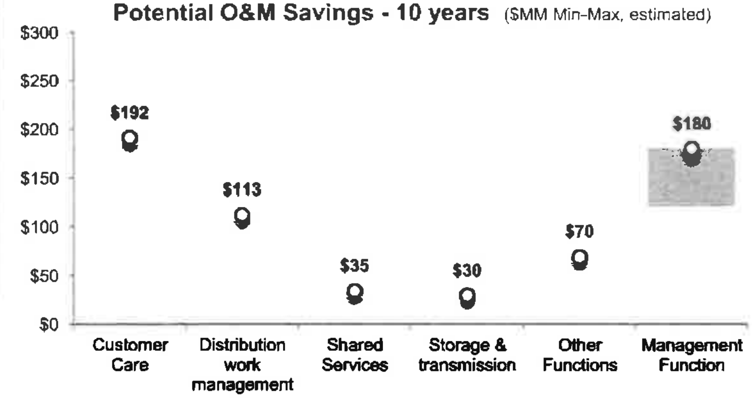
Opportunity	**There are opportunities to rationalize the management structure and other functions within the integrated utility. Identifying a single management structure and Executive Management Team will be one of the first integration efforts** **Broader workforce reductions are expected to occur at a much more gradual pace as various integration initiatives are undertaken over the 10 year deferred rebasing period**
Scope	Considerations by the new management team with respect to any workforce reductions will require a review and alignment of operational processes and the related systems, and the staff necessary to execute these processes so that safe, reliable business operations continue and service levels are maintained
Capital Estimate	There is approximately **$20 M** of severance costs that have been considered as capital that will occur in the first year.
Opex Savings	The savings from the rationalizing of the management structure is estimated to be **$180** M over ten years. A 7% reduction in combined utility annual salaries and wages of $285 M (net of capitalization) This estimate for potential savings is considered aggressive as a percentage of the management level salaries. The estimate for management structure changes is input as $20 M per year with a first year severance cost of $20 M
Basis for Estimate	Based on compensation costs of to duplicate of Management functions

Align and rationalize management structure for combined Utility

Potential Capital Investment - 10 years ($MM Min-Max, estimated)



Potential O&M Savings - 10 years ($MM Min-Max, estimated)



Filed: 2018-03-28, EB-2017-0306/EB-2017-0307, Exhibit C.FRPO.1, Attachment 1, Page 17 of 35

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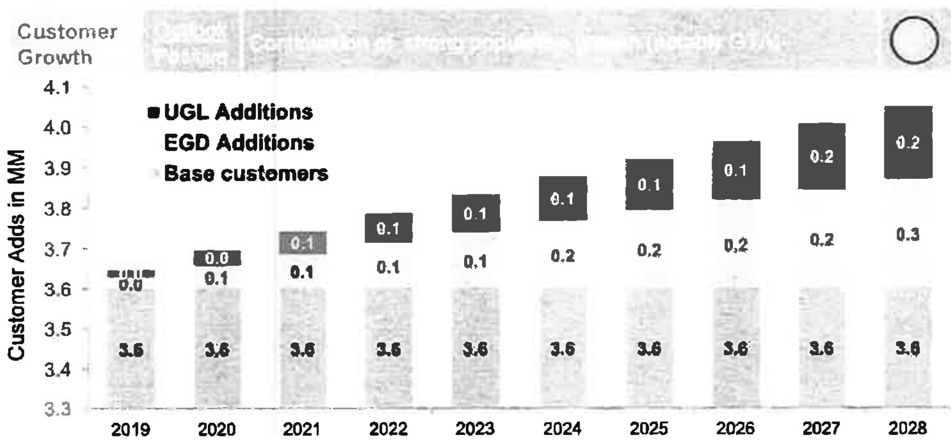
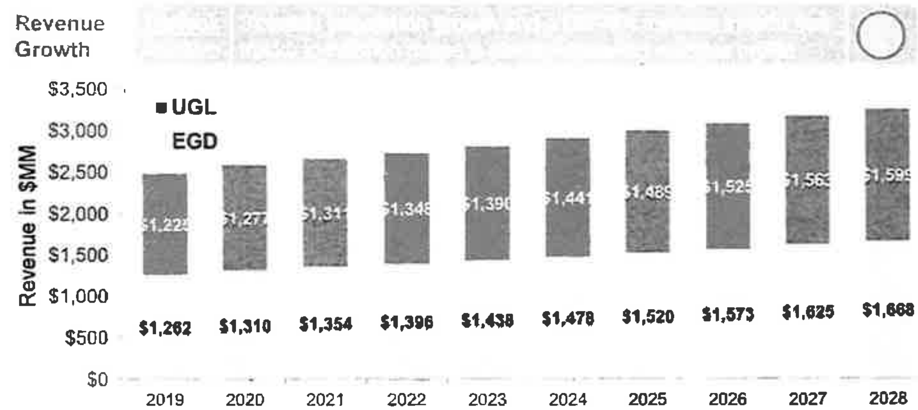
Base Case Key Economic Assumptions

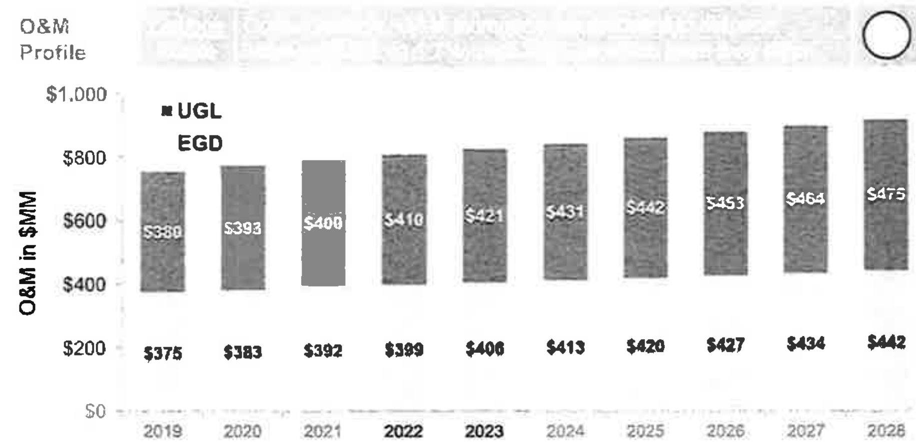
Customer growth escalates at 0.93%, or 50,000 per year, in the near term (driven by continuing trend of rapid GTA growth), tapering to 0.84%, or 42,000, in the long term

Revenues growth driven by: customer addition profile and price cap escalator of 1.73%

O&M escalates at 2.0% in the near term, dropping to 1.73% mid-long term







Integration Financial Evaluation

Base Case Key Economic Assumptions

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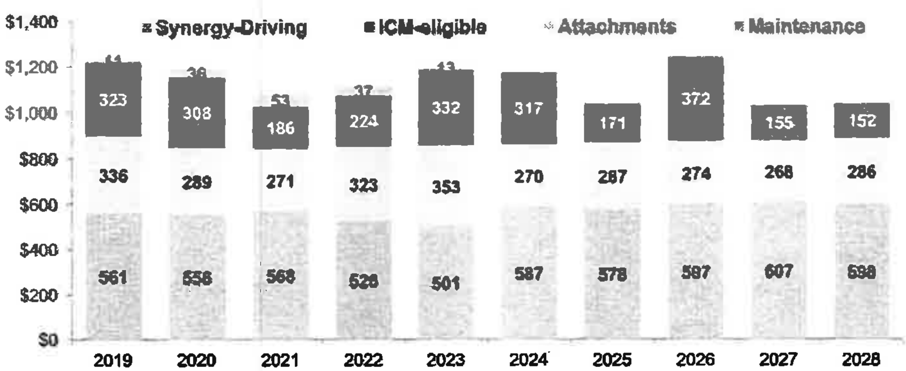
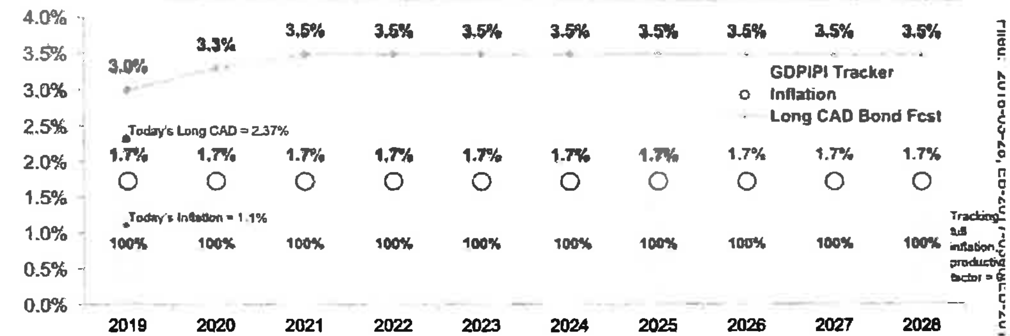
- Capital expenditures based on 10 year Asset Management Plans which is filed at base year; Incremental Capital (discrete projects) added to rate base at in service year Allowed ROE amounts through the ICM
- The Long CAD Bond forecast has a 50 bps increase from 2019 to 2021 and 113 bps increase from todays rate to 2021
- Allowed ROEs are based on utility forecast which is primarily driven by the Long CAD Bond
- Zero cost sharing assumed over the 10 year period (i.e. Returns on equity are less than the 300 bp threshold)

Capital Program

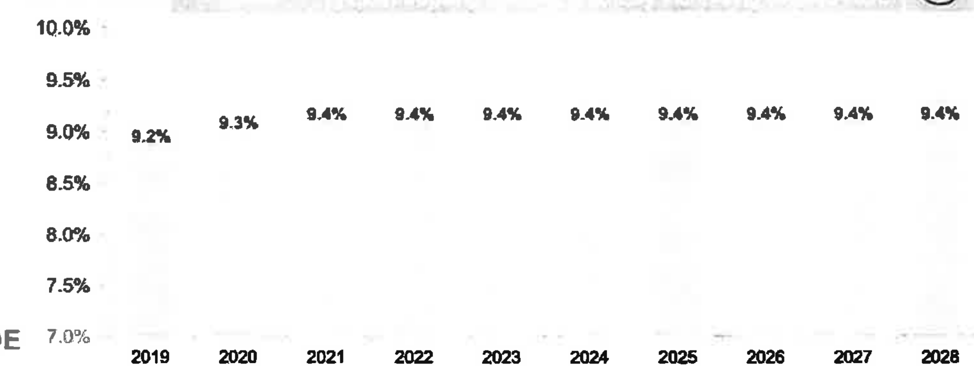


No rate adjustment under MAADs for higher interest rates or Allowed ROE

Inflation & Interest Rates



Allowed-ROE



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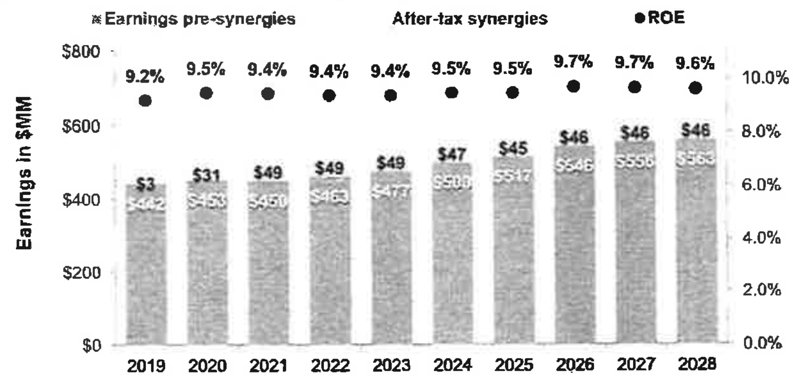
Base Case Financial Summary

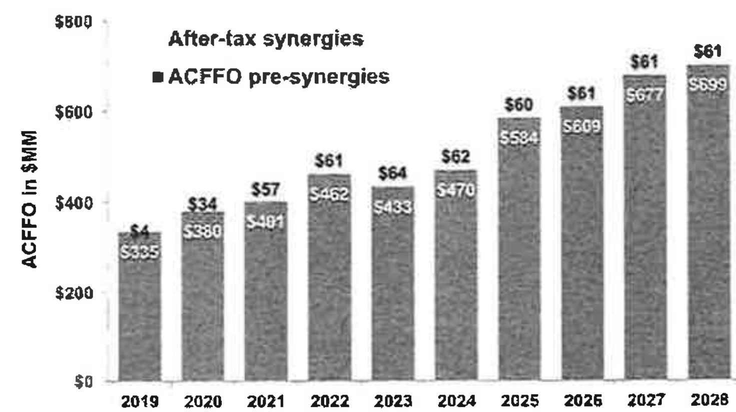
Financial Summary

Proposed Filing: 10 year MAADS (Escalated Price Cap + Incremental Capital Module)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
EGD	235	245	240	247	256	272	278	304	309	316	
UGL including deferred tax adj	207	208	210	215	220	228	238	242	247	247	
Utility Earnings before synergies	**442**	**453**	**450**	**463**	**477**	**500**	**517**	**546**	**556**	**563**	
Synergies	3	38	63	70	81	85	85	85	85	85	**680**
Drag due to funded synergy capital	(1)	(4)	(9)	(15)	(18)	(18)	(18)	(17)	(17)	(16)	**(133)**
Sub-Total Pre-Tax Synergies	2	34	54	55	63	67	67	68	68	69	**547**
After-tax impact of synergies	**3**	**31**	**49**	**49**	**49**	**47**	**45**	**46**	**46**	**46**	**412**
Utility Earnings with synergies	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
Earnings Sharing (2024 – 2028 >300bps)	-	-	-	-	-	0	0	0	0	0	
Utilities Earnings after sharing	**445**	**483**	**500**	**512**	**526**	**547**	**562**	**591**	**603**	**609**	
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%	

Average of $42 Million/ year of after –tax synergies provides opportunity to achieve earnings in excess of Allowed ROE while delivering inflationary rate increases to customers





[1] ACFFO is aligned with utility STIP measurement calculation method and has been grossed up (pre-tax and interest expense)
[2] Capital structure 36% equity/ 64% debt
[3] Income tax rates constant at 26.5%

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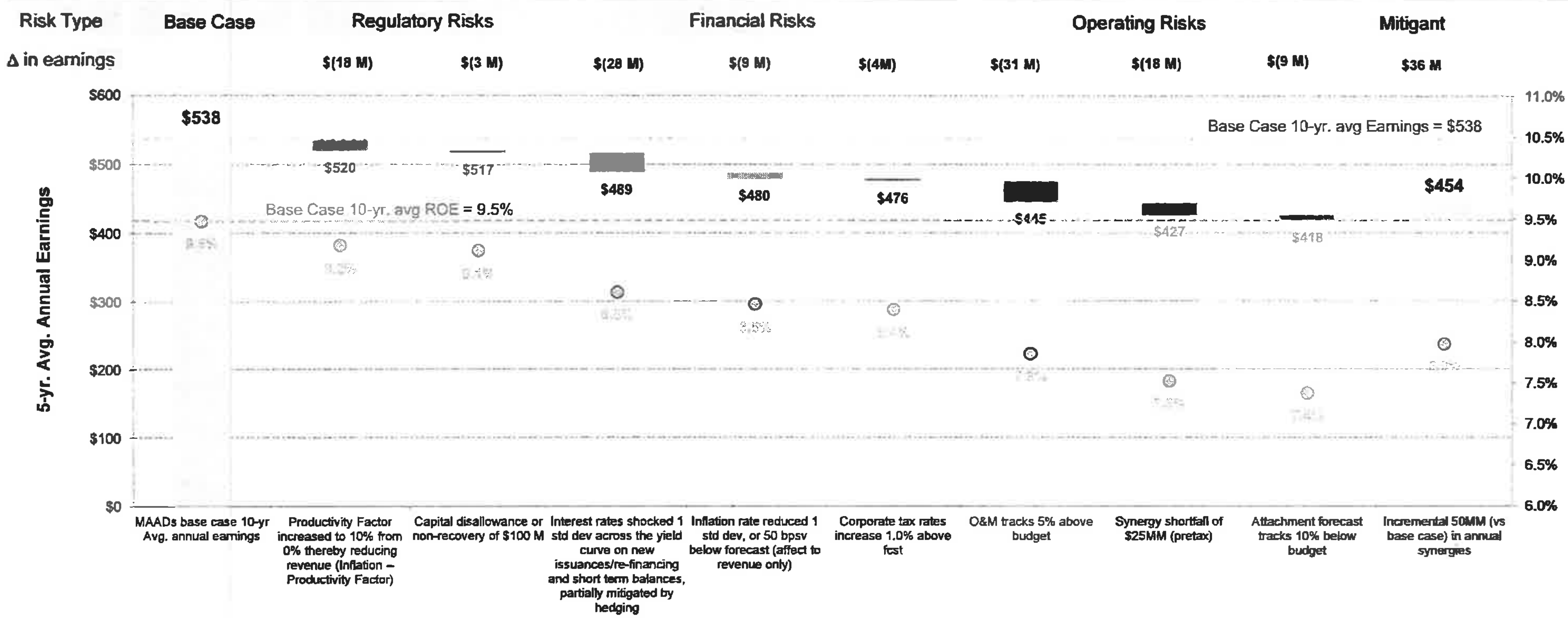
Summary of Risks by Type



Interest rates increasing represents the largest financial risk

In April 2015, the OEB established a policy that requires electric distributors to fully recover distribution costs from residential customers through a fixed monthly charge. Recovering natural gas distribution costs through a fixed monthly charge would be consistent with the OEB policy for electric distributors. Management is evaluating the movement to a fully fixed charge approach to collection of distribution costs. Under the MAAD policy, the company is able to file for rate design modifications with the appropriate justification for OEB review. An application to move to a fixed charge approach would be filed in 2019 or 2020 depending on the outcome of the integration application.

Externalities during deferred rebasing term: Over the 10 year rebasing deferral period externalities such as increased regulations, pipeline integrity regulations and costs, costs greater than inflation, depreciation increases and no 2019 rate rebasing are potential risks which management may have to mitigate. Where these or other externalities impact the company in a significant manner, Management will look to file applications seeking appropriate treatment by the OEB. For example, a material change in environment regulations that resulted in a very material operating or capital costs for the integrated utility could result in management seeking a regulatory application since this would not reflect normal operating and capital risks.

Financial Overview

No Harm Test

A key component of the No Harm Test is that the ratepayer will not pay more under a plan where the utilities integrate relative to what they would have paid in the absence of integration. Table 1 below shows the No Harm Test revenue variance which is the difference between EGD and Union's proposed revenue requirement from 2019 to 2028 as separate utilities versus the integrated utility operating under a Price Cap framework where 2018 revenues are escalated annually at Inflation (~1.7%). Table 1 shows that the customer rate component of the No Harm Test is met. Over the ten years, customers will pay an estimated $442 M less under the MAAD framework then what they would have paid if EGD and Union operated as standalone utilities.

Table 1: OEB No Harm Test Financial Summary

No Harm Test
Utility Stand Alone Applications vs Utilities with Revenue escalated @ Inflation
Revenue Variance [Excess / (Shortfall) in $ Million]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
UGL	(32)	(33)	(34)	(35)	(34)	(36)	(39)	(34)	(29)	(23)	(330)
EGD	22	13	1	(9)	(21)	(26)	(25)	(25)	(24)	(19)	(113)
No Harm Test Variance	**(10)**	**(20)**	**(33)**	**(44)**	**(55)**	**(62)**	**(64)**	**(59)**	**(53)**	**(43)**	**(442)**

As stated above, the company will be filing to adjust Union Gas's 2019 base rates to reflect the stoppage of a deferred tax refund consistent with the current OEB ruling. Table 2 shows a reduction of the $442 M revenue shortfall identified in the No Harm Test by $170 M. Management will have to offset the residual $272 M revenue shortfall through the utility integration of systems, business functions and organizational restructuring. Under a MAAD framework customers will pay approximately $27 M less (annually) than what they would have paid if the two utilities did not integrate.

Table 2: Pre-Integration Revenue Variance

Revenue Variance Adjusted for UGL Tax Adjustment in 2019 Base Rates
Revenue Variance [Excess / (Shortfall) in $ Million]

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Revenues from UGL Deferred Tax	17	17	17	17	17	17	17	17	17	17	170
Pre-Integration Revenue Variance	**7**	**(3)**	**(16)**	**(27)**	**(38)**	**(45)**	**(47)**	**(42)**	**(36)**	**(26)**	**(272)**

Table 3 outlines the impact from an initial forecast of the integration benefits. Management's initial review of restructuring the combined management and administrative staffing and the integration of systems and business functions of EGD and Union indicate a potential estimate of pre-tax savings of $567 M over ten years. This savings estimate is unclassified. Management estimates the potential for savings, net of costs, in a range of between $350 M and $750 M based on the requirement to invest capital in the range of between $50 million to $250 million.

The post-integration financial result is an estimated benefit of $122 million (pre-tax) over ten years relative to a higher allowed ROE during the ten year period. The 10 year average achieved ROE post-integration is estimated to be 9.78% versus the 10 year average allowed ROE of 9.65%. While the OEB allowed ROE had been used as a comparator, it is not possible for gas utilities to file and receive annual cost of service rate changes to incorporate changes in the OEB allowed ROE. In October 2016, the OEB issued the Handbook for Utility Rate Applications that states that gas utilities in Ontario no longer qualify for annual cost of services filings. Some type of custom rates with a period in excess of one year must be filed.

During the ten year period customer rates are estimated to increase at the rate of inflation and rate increases will exceed inflation only in the years that the integrated utility successfully accesses the OEB Incremental Capital Module.

Table 3: Initial estimate of the integrated utility earnings excess / (shortfall)

10 Year EGD and UGL Earnings Profile under MAAD
($ Million)

$ Millions	2017F	2018B	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total	Average
EGD and Union at MAAD base case														
Achieved Utility Earnings before synergies:														
- EGD (PCI)			247	247	250	253	254	255	260	264	269	275	2,573	
- UGL (PCI) including accumulated deferred tax adjustment			205	210	213	215	219	222	223	228	233	238	2,206	
Total Achieved Utility Earnings before synergies			452	457	463	468	473	477	484	492	501	513	4,779	
Earnings impact of synergies			5	31	41	41	50	55	56	52	47	49	425	
Achieved Utility Earnings with synergies			457	488	504	509	523	532	539	543	548	561	5,204	
Earnings sharing			-	-	-	-	-	-	-	-	-	-	-	
Achieved Utility Earnings with synergies after ESM			457	488	504	509	523	532	539	543	548	561	5,204	
Achieved ROE			9.40%	9.76%	9.84%	9.74%	9.83%	9.82%	9.82%	9.80%	9.81%	9.99%		9.78%
Allowed ROE	8.78%	9.11%	9.28%	9.28%	9.49%	9.66%	9.80%	9.80%	9.80%	9.80%	9.80%	9.80%		9.65%
ROE (Achieved vs Allowed)			0.12%	0.48%	0.35%	0.07%	0.03%	0.02%	0.01%	0.00%	0.01%	0.19%		0.13%

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.

E.B.O. 195

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF an Application by Westcoast Energy Inc. and its subsidiaries Centra Gas Ontario Inc. and Union Gas Limited for leave of the Lieutenant Governor in Council to amalgamate Centra Gas Ontario Inc. and Union Gas Limited;

AND IN THE MATTER OF Undertakings given by Westcoast Energy Inc. and its subsidiaries Centra Gas Ontario Inc., and Union Gas Limited, dated July 22, and November 27, 1992 respectively.

BEFORE: M. C. Rounding
Chair and Presiding Member

P. Vlahos
Member

H. G. Morrison
Member

REPORT OF THE BOARD

March 7, 1997

1. INTRODUCTION

1.1 THE PROCEEDING

1.1.1 Westcoast Energy Inc. ("Westcoast"), Centra Gas Ontario Inc. ("Centra") and Union Gas Limited ("Union") (collectively "the Companies" or "the utilities") applied to the Ontario Energy Board ("the Board") on September 25, 1996 ("the Application") under section 26 of the Ontario Energy Board Act, R.S.O. 1990, c. O.13 ("the OEB Act" or "the Act") for leave of the Lieutenant Governor in Council ("the LGIC") to amalgamate Centra and Union. The Companies have also proposed to make certain amendments to the undertakings given by the Companies to the LGIC, dated July 22, 1992 and December 16, 1992 respectively ("the Undertakings") as a result of the proposed amalgamation. The Application was assigned Board File No. E.B.O. 195.

1.1.2 On October 11, 1996 the Board issued a Letter of Direction requiring the Companies to publish a Notice of Application.

1.1.3 On November 21, 1996, the Board issued Procedural Order No. 1 setting out certain dates relating to the hearing of the Application.

1.1.4 On December 6, 1996 a Technical Conference was held for the purpose of reviewing the Companies' prefiled evidence and defining the issues related to the hearing of the Application. At the Technical Conference it was noted that the Companies had completed a review of the alternatives for naming the merged company and that it is to be named Union Gas. The chosen name for the merged company will not be used

2.2.9 With respect to the holders of preference shares there is an issue as to the relative seniority of the preferred shares of the two companies. The evidence was that Centra will redeem its preferred shares in accordance with the applicable preference share agreements. The total premium related to the redemptions was forecast to be $38,000.

2.3 BENEFITS

2.3.1 The Companies forecast annualized savings from the merger of approximately $2.1 million, after absorbing one time costs and allowing sufficient time to implement the programs that would generate the savings. The savings stem from not having to maintain two legal entities, thereby reducing duplication in planning and administrative activities, including regulatory costs.

2.3.2 The anticipated annual savings would arise in the following areas:

Operations	$ 625,000
Finance	370,000
Treasury	336,000
Regulatory	200,000
Gas Supply	58,000
Insurance and Licences	283,000
Other administrative savings	250,000
Total Savings	$2,122,000

2.3.3 The full $2.1 million in savings would be realized by the year 2000. The savings in 1998 are projected at $1.7 million and in 1999 at $2.0 million.

2.3.4 A description of the components of the forecast savings is provided below.

4. BOARD FINDINGS AND RECOMMENDATION

4.1 THE PUBLIC INTEREST

4.1.1 As stated earlier, in reporting to the LGIC on the proposed merger, the Board bases its opinion on a consideration of the public interest.

4.1.2 In reaching its conclusion, the Board uses certain general parameters it has formulated over the years as a guide in assessing the overall public interest. The relative importance of each of these parameters can vary and has varied from one situation to another, but in general they form the basis for the Board's opinion in examinations of this type. In this specific application, the parameters can be stated as follows:

1. Impact on rates and service,
2. Interest of shareholders and impact on investors,
3. Impact on employees,
4. Impact on communities,
5. Regulatory implications,
6. The public interest generally.

Regulatory Implications

4.1.25 Fundamental changes to two large regulated companies must also be examined with a view to ensuring that the Board will be able to continue to discharge its regulatory mandate. There was no evidence and no party argued that the Board's responsibilities would be compromised as a result of the merger.

4.1.26 The current existence of three major gas utilities in Ontario is valuable to the regulatory process in that comparisons can be made among the utilities. On the other hand, the merged company will become more comparable to Consumers Gas, making comparisons in certain ways more meaningful.

4.1.27 The merger of Centra and Union will reduce the regulatory burden as a result of fewer rates cases and other applications. However, the Board anticipates that rate reviews of the merged company over the next few years will entail some unique complexities, particularly in the areas of cost allocation and rate design. The Board will need to be prepared to examine, in future reviews of the merged utility, possible effects which could not be presently identified.

The Public Interest Generally

4.1.28 As the Board has commented in previous cases, one of the problems in assessing the public interest is that a benefit to one group is often a detriment to another. The Board's role is to weigh all the benefits against all the detriments and decide in the overall public interest.

4.1.29 The Board has had many occasions to consider the public interest as an accommodation of conflicting interests. Some situations were highly contested, others less so. Other than certain future cost allocation and rate issues, what is notable in the present case is the absence of serious conflicting interests.

4.1.30 At the conclusion of the evidence, the Board asked the Companies whether they could provide more concrete assurances to the Board regarding cost allocation and rate matters upon which it could base a positive recommendation to the Government. The

Board accepts the Companies' position that the ongoing scrutiny of this Board through future regulatory proceedings, should provide sufficient comfort to the Board to support a positive recommendation to the LGIC.

4.1.31 The broader public interest also demands that the Board examine the proposed merger in a wider industry context. In this regard, the Board has not identified any potential problems or obstacles likely to be created by the proposed merger which may work against industry developments and goals. In an Ontario context, the Board had no evidence to suggest that inter-fuel competition and current reviews of restructuring of the utility industry along the lines of monopoly and non-monopoly businesses would be compromised in any obvious way.

4.1.32 Given the nature of the two firms to be merged, i.e. utilities with specific franchise areas not competing with each other, the typical concerns that arise from market concentration are not as applicable in this instance. For example, there is no issue whether market concentration in this case will restrict output or increase prices, or whether competition at the wholesale or retail level will be compromised. In any case, thc two utilities are presently commonly owned and operated.

4.1.33 For a number of the parameters the Board examined, no harm has been found to result from the merger, and in some, positive benefits will result. Moreover, the proposed merger secures the savings that resulted from the shared services initiative by combining the two utilities. Overall the result is positive.

4.1.34 There was discussion at the hearing whether the Board should use the more stringent positive test of the public interest or the less stringent "no harm" test. The Companies commented that the proposed merger is in the public interest but the Board need not adopt this more stringent test in reporting to the LGIC. Others took the position that the test ought to be a positive one.

4.1.35 In view of the Board's positive conclusion regarding the benefits of the proposed merger, it is unnecessary for the Board to consider how confidently it would have recommended approval to the LGIC had the Board found the proposal met only the less stringent test.

4.1.36 The Board finds that the proposed amalgamation is in the public interest.

4.2 RECOMMENDATION

4.2.1 **The Board recommends to the LGIC that the proposed amalgamation of Centra and Union be approved, subject to the acceptance of the Undertakings as recommended by the Board.**

4.2.2 The Board's recommendation to the LGIC for approval of the merger application is irrespective of the Board's findings in the E.B.R.O. 493/494 relating to the capital structure, deferred tax matters, and Westcoast Corporate Centre charges, either in those rates cases or in future rates cases. Those are matters which are strictly rate related and will be decided on their own merits. The Board therefore has concluded that its findings are not dependent on the conclusions of the rates panel in E.B.R.O. 493/494, and has not viewed it to be necessary to wait for the outcome of these matters in the pending rates decision before it could make its recommendation to the LGIC.

4.2.3 Should the Board's decision in E.B.R.O. 493/494 cause any change in the plans of the Companies, it is expected that the Companies will advise the LGIC and the Board, prior to the LGIC granting approval.

4.2.4 The Board notes that approval by the Ontario Securities Commission is also required before the merger is legally effected, but the Board does not view it as necessary to condition its recommendation to the LGIC on that approval.

4.2.5 The Board's findings and recommendations with respect to the Undertakings that should be required of the merged company are set out in Chapter 5.

6. DEFERRAL ACCOUNT

6.0.1 In a letter to the Board dated January 8, 1997, the Companies requested that the Board issue an accounting order to record in a deferral account the one time O&M costs to effect the merger. These costs, amounting to $2.0 million, were presented at the merger hearing. The Companies requested that the accounting order request be reviewed as part of the merger hearing.

6.0.2 The Companies proposed to amortize the costs in proportion to the forecast savings so that no negative rate impact would result from the incurrence of upfront operating costs. This treatment would be consistent with the treatment approved by the Board in the shared services initiative.

6.0.3 Certain parties questioned the appropriateness of certain costs on different grounds. It was suggested that certain costs represented double-counting, or that they should have been forecast for the rates case. It was also suggested that Westcoast stands to benefit from the merger and should consequently bear the costs.

6.0.4 The Board observes that $236,000 of the proposed one time O&M costs were incurred in 1996. This amount consists of $57,000 in Legal and Treasury, $167,000 in Regulatory and $12,000 in Communications. The Board considers the Companies' request to include these costs contrary to sound regulatory practice. In the normal course, the Companies would not include in their forecast test year cost of service, any costs that were incurred in an historical year. These are clearly out of period costs; they should be borne by the utilities' shareholder, not by the ratepayer. The