EB-2017-0306/307

Enbridge Gas Distribution Inc. and Union Gas Limited Application for approval to amalgamate Enbridge Gas Distribution Inc. and Union Gas Limited and for approval of a rate-setting mechanism and associated parameters from January 1, 2019 to December 31, 2028

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

June 17, 2018

John Lawford/Ben Segel-Brown, Counsel for Vulnerable Energy Consumers Coalition

Public Interest Advocacy Centre:
1 Nicholas Street, Suite 1204
Ottawa, ON K1N 7B7
613-562-4002
piac@piac.ca

Direct:
bsegel-brown@piac.ca
613-864-6322

1.0 SUMMARY OF THE SUBMISSIONS

1.1 VECC submits that the Applicants have met the no harm test provided the following conditions are imposed:

(i) The Board set the rate term for a period of no more than 4 years prior to a full cost of service rebasing that also addresses rate harmonization;

(ii) The Board adds a stretch factor to the proposed rate formula to allow for the known productivity enhancements that will be achieved over the near future and irrespective of whether the two utilities amalgamate;

(iii) The Board convene a proceeding with stakeholders to review the Natural Gas markets for storage and transportation in Ontario ("NGEIR Review"); and,

(iv) The Board convene a proceeding to review the gas supply and gas transportation and storage plans, reference price and other facets of the quarterly gas adjustment mechanism that would apply to an amalgamated utility.

1.2 If the Board declines to approve the application as proposed then it should give direction to Union Gas and Enbridge Gas Distribution (EGD) as to the process for setting 2019 rates.

1.3 VECC has used the Board's approved Issues list in making its submission.

2.0 NO HARM TEST

Have the applicants appropriately applied the 'No Harm" test in this case, including in consideration of the OEB's statutory objectives in relation to natural gas?

Have the Applicants met the test?

2.1 In our submission the Board should consider two aspects of the no harm test. The first is from the perspective of the in-franchise rate payers and primarily the rates that they will pay for distribution service. The second is from the perspective of the ex-franchise users of storage and transportation service and the broader economic interest of Ontario residents.

2.2 With respect to in-franchise rate payers <u>and without consideration of the proposed rate plan</u>, then in our submission the Applicants would meet the no harm test. However, in the alternative, if the proposed rate plan accepted as filed and cost allocation and rate design issues for the amalgamated utility are deferred for a period of 10 years then consumers would be worse off than under the status quo. It is our submission that the proposed rate plan fails to protect the interests of consumers with respect to prices of gas service.

2.3 The concept of "no-harm" should be considered in a broad sense and over the long term. It does mean that all customers in all places must see rates no higher than in the alternative. That would be, in our view, unrealistic and in any event unattainable. Any change in rates affects customers differently and any application would fail if it had to be proven that no customer will be worse off after the transaction. What the no-harm test should demonstrate is on balance customers will be better, or at least no worse off. It is important to demonstrate that the rates paid by those customers are, and will remain, just and reasonable.

2.4 With respect to prices, in this case the Applicants propose a 10 year rate deferral period. In our submission, the Board cannot with any certainty know that on balance customers will not be made worse off under the Applicant's rate deferment proposal. That is because with respect to fairness and reasonableness the rate issue in an amalgamation is a much one of the level of prices as it is the impact of rate harmonization and common cost allocation. Inevitably if there is to be a utility with shared assets, rates must be determined on one basis and without consideration of the past. Certainly that is the Board's policy with respect to consolidating electricity distributors.

2.5 In that event it is likely some customers will be made worse off than under the status quo due to changes in rate design or cost allocation. However, if the two Utilities were to amalgamate and rebase under a common cost structure we believe there are sufficient economies from the merger to make on balance customers better, and no worse off, than the status quo.

2.6 For these reasons we believe the Board should approve the amalgamation, but not the rate plan as filed.

2.7 In our view the Board should consider both the immediate but also the long term view of the proposed rate plan. If the merger is approved the future necessarily will be to commingle assets and operations. While the larger issue of how to create a common cost allocation might be deferred for a few years while Amalco rationalizes it operations, others, like those with respect to the allocation of regulated storage[1] should be addressed in the immediate term.

2.8 Irrespective of whether it applies to sector, natural gas or electricity, one of the logical flaws in the deferment of "rate rebasing" for prolonged periods when utilities amalgamation is the issue of the deferment of cost allocation and rate design. Price cap forms of rate regulation are best used in situations where the Utility is in a stable form. It is clearly

[1] AIC, par. 26, page 9

problematic when used over such a long period and where during that period assets and operations of different utilities will be commingled. In that case, which is what is before the Board in this Application this form of rate making will lead to ever increasing difference between who incur costs and who pays for them. Fundamentally price cap rates delink cost causation from the rates. This is not so much a problem if there is little reason for causation to differ over time. That is certainly not the case in an amalgamation where there will be cost allocation changes both of an inter- and intra-class nature. Over time what happens in these circumstances and certainly in this case, is that there will be intra-class misallocations almost immediately. The most obvious in this case is regulated storage where the Applicants suggest that customers of one utility – Amalco – continue to use their designated regulated storage as if they continued to be customers of two utilities. Overall the implications of intra class inequities is clear from a simple consideration of the differences of the existing per customer operating costs of the two Utilities[2]

Table 2
Comparison of O&M per Customer

	EGD			Union		
	O&M $ millions	Customers	$ O&M per Customer	O&M $ millions	Customers	$ O&M per Customer
2014[7]	408	2,063,837	198	380	1,419,499	268
2015[8]	431	2,094,681	206	383	1,436,924	267
2016[9]	450	2,124,683	212	398	1,458,720	273

2.9 The above table demonstrates that rate harmonization and the supporting comprehensive cost allocation study that would support harmonization would likely result in a decrease in rates that some Union customers pay while increasing the costs of some Enbridge customers.

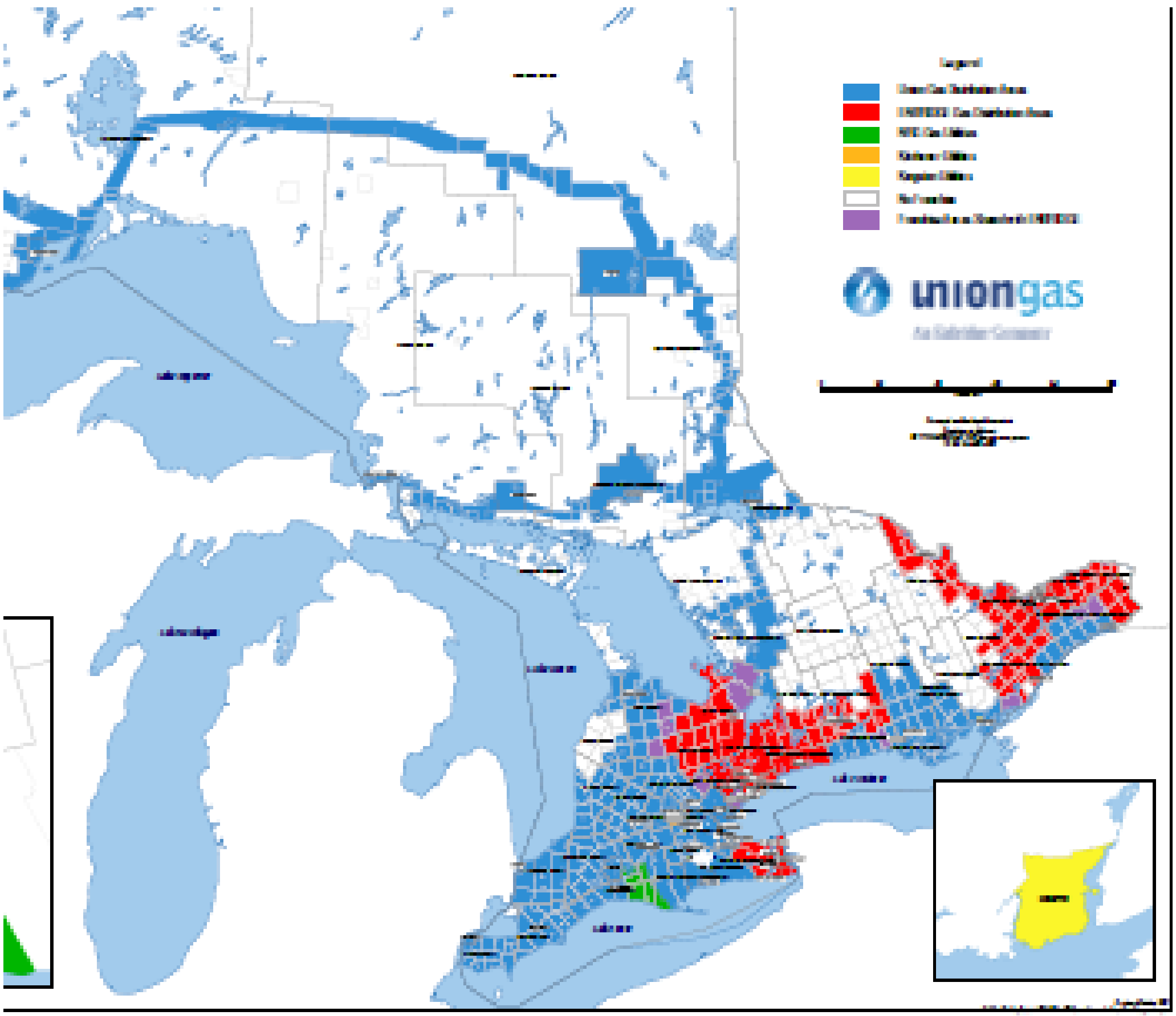
2.10 While rate harmonization is not part of the proposal it is nonetheless an inevitable part of amalgamation. It is not only Board policy with respect to the electricity distribution sector. It has been noted that Union maintains zone differences from its prior acquisition of Centra Gas. However, it is also clear that Union's northern zone is particularly different from its southern distribution areas of service. Most notably the service to sparsely populated areas of northern Ontario from gas supply taken exclusively from taps off the TCPL mainline.

2.11 Union's Southern zone on the other hand is broadly similar to the service zones of EGD. It would be difficult, for example, to explain to future Amalco customers why a residential customer served in Mississauga pays not just a different rate, but also under a different rate structure, than a Union customer in Oakville. Likewise the cost drivers for customers in Enbridge's Ottawa region have more in common with the Union customers served to the

[2] Exhibit B, Tab 1, page 13

area just to the south of Ottawa than they do with the customers served by Union in Windsor Ontario. Certainly as consolidation moves forward this will become more, not less true as the two Utilities rationalize their operations.

2.12 The Map below shows how embedded the service territories of the two Utilities currently are. One can easily imagine a future in which there are three rate zones for Amalco, Northern, South-Central and Eastern[3].



[3] Exhibit B, Tab 1, Attachment 3, page 1

2.13 In our view the Board cannot simply turn a blind eye for 10 years to the future implication rate fairness resulting from amalgamation. Future Amalco customer rates which clearly discriminate between neighboring customers who have identical cost to serve cannot remain just and reasonable based on some historical event. The Board has an obligation to ensure that all customers are treated fairly and that means to the extent possible customers in similar circumstances are treated in similar ways. Indeed that is the premise of all regulated rate making. If, as is inevitable, as time goes by and operations become more and more integrated, then customers will rightly demand justification for the fact that a residential customer in St. Catherines is charged the same rate as one in Toronto, but something more or less than their closer neighbour in Hamilton. In a 10 year deferral the Board with each passing year will have a smaller defense against the charge it has abrogated its responsibility to properly rate regulate one of Canada's largest monopoly enterprises.

2.14 With respect to the ex-franchise broader application of the no-harm test to the matters of storage and transportation services the Applicants rely in part on a singular letter from the Competition Bureau. The letter is presented to the Board as evidence of a "no action – letter"[4].

> I am writing in regard to your letter of October 3, 2016, in which you requested on behalf of Enbridge Inc. and/or its affiliates and Spectra Energy Corp and/or its affiliates the issuance of an Advance Ruling Certificate ("ARC") pursuant to section 102 of the *Competition Act* (the "Act") or in the alternative a No-Action Letter, and the merger notifications of the parties received on October 3, 2016 in accordance with section 16 of the *Notifiable Transaction Regulations* with respect to the above-noted transaction (the "Transaction").
>
> Based on the information provided by the parties, and information obtained from other sources, it would not be appropriate to issue an ARC as requested by the parties. However, the Commissioner of Competition (the "Commissioner") does not, at this time, intend to make an application under section 92 of the Act in respect of the Transaction. Please note that section 97 of the Act provides a one year period following completion of the Transaction during which the Commissioner may bring an application to the Competition Tribunal.

2.15 While the correspondence does, in fact, state that the Competition Bureau does not intend <u>at this time</u> to make an application it does reserve the right to do so for one period. It also explicitly denies the Applicant's the certainty of an Advance Ruling Certificate.

2.16 There is little evidence in this proceeding to fully understand why the more conclusive evidence of no public harm in the form of an ARC was not provided. However, the Board's clear jurisdiction to forebear rate regulation of the Ontario storage activity and its equally

[4] JT3.11

clear jurisdiction over the intra-provincial Union Gas transportation services are, in our view, the most likely reason. Given that jurisdiction and the Board's expertise, in our view the reason for a tentative "no action" letter is the Bureau's reliance on the Ontario Energy Board to protect the public from monopoly or monopsony activities.

2.17 Having said that, VECC does not believe this amalgamation results in any immediate or fatal issue to the gas storage or transportation markets of Ontario. However, it is clear that if approved there would need to be consideration of its impact on these areas of the gas market in Ontario. For example, there are issues with respect to self-contracting, regulated storage allocation and in the medium to longer term, transportation arrangements to support a combined natural gas supply plan. It is also obvious that with this amalgamation Ontario will lose some of the benefit of diversity. Rather than have two large utilities vying for market resources and observing each other's activities, the market will be more monolithic. Markets function best when there are a large number of participants, none of whom control significant portions of the market.

2.18 If the Board is inclined to grant approval of this application VECC urges that it do so with the intention of revisiting both natural gas planning for the amalgamated utilities and the underlying basis of NGEIR and the practical application of that in the STARR requirements. Doing so would provide two things. First, comfort that the Board is cognizant of any implications caused by the elimination of a major independent participant in the natural gas market of Ontario. Second, that the reporting and other rules respecting the monitoring of these markets remains robust in light of the amalgamation.

3.0 REBASING DEFERRAL

Is deferral of rebasing appropriate in the context of this application?

3.1 VECC submits the 10 year period is not reasonable. It is not supported by Board policy with respect to gas utilities. Furthermore a 10 year hiatus will require the Board to postpone a comprehensive cost allocation and rate design for at least 10 years. In our view that would result in rates which cannot be justified. Finally a 10 year deferral under the proposed rate plan unjustly enriches the Applicants at the expense of ratepayers.

3.2 The Applicant's submit that the proposal is in keeping with the Board's policies on Electricity Distribution Amalgamation. In our view there is no merit to this supposition. In fact the Applicants have in our view twisted themselves into knots trying to parse together phrases plucked from various electricity, gas and general Board policies to create a narrative that the Board is seeking consolidation in the natural gas sector. This is simply not true. The Board has no explicit policy with respect to the consolidations of natural gas distributors. Why should it – it only rate regulates three, two of which already are among the largest utilities in Canada.

3.3 It is obvious that the Board's "consolidation" policies are directed at the much more diverse electricity distribution sector in Ontario. That policy was driven by the Board's difficulty in regulating a large number of small utilities and in the (in our view misplaced) view that there are significant economies of scale to be had in the electricity sector through consolidation. The policy was created in an atmosphere where the prior provincial government continually expressed informally (though not in legislative or directive mandates to the Board) the urgency of electricity distribution consolidation. It was done in light of the particular tax penalties to the municipally held electricity distribution companies that would be incurred if and when a sale was contemplated to a private sector entity. None of these unique factors exist, or have every existed in the natural gas distribution sector.

3.4 The fact is that this proposal would create the largest distribution utility in Canada. As such, and as discussed above, issues are raised not least in the natural gas storage and transportation market that will need to be considered as part of any approval. Had the Board a policy with respect to consolidating the two of the largest utilities in the province then presumably it would have considered the impact on natural gas storage and transportation – it did not. In any event the Board cannot be fettered by policies which if anything, include as an afterthought the natural gas sector.

3.5 A prolonged rebasing deferral would also forestall the Board's review of the cost allocation and rate design issues of both current utilities. As discussed above this is especially problematic in the case of Union Gas, where there are clear cost allocation issues that need to be addressed to deal with specific large projects like the Panhandle pipeline reinforcement.

If so:

a) What is the appropriate deferral period?

b) Is an earning sharing mechanism (ESM) appropriate and if so, what should that mechanism be and when should it apply?

c) What additional considerations and requirements are appropriate to protect the interests of customers pending rebasing?

d) What additional considerations and requirements are appropriate to protect the interests of customers pending rebasing?

3.6 In our view four years would provide the Utility with an opportunity to perform many of the critical studies in order to provide a new cost allocation and rate design proposal. However, in our view it would be reasonable to have the amalgamated utility rebase no later than for the 2022 rate year, i.e. in four years. Under this scenario the proposed 50/50 sharing after 300 basis points might be reasonable.

3.7 However, we recognize that there is no definitive answer to balance providing incentives for the amalgamating utility to find efficiencies with the need to provide customer rates which are just and reasonable on both a price and allocation basis. One way to do this would be to find a balance within the earning sharing mechanism which provides incentives to consolidate effectively and efficiently in order to maximize benefits to shareholders during the deferment period, while ensuring that any windfalls are shared with customers.

ESM Sliding scale

3.8 Conversely if the Board is inclined to provide a longer rebasing period it should offset the risk by reducing the benefits available to the Utility through earning sharing. One way the Board could achieve this balance is to alter the earning sharing threshold and the proportion of sharing in each year of the deferment. For example in the first year, sharing would be on the basis of 90/10 (in favour of the utility) and in the last year of a 10 year deferment in would be 0/100 (in favour of customers).

3.9 Likewise the basis point threshold could be adjusted each year in decrements of 30 basis points. In the first year of the plan the ESM would be calculated above a 300 basis point threshold, but in final 10th year there would be no threshold. This would provide a sliding benefit to shareholder/customer scale where in essence shareholders receive 100% of any overearnings in the first year of the plan while customers receive 100% of any overearnings and in the final year of a 10 year deferment.

3.10 Using this, or some other form of sliding scale maximizes incentives to the Utility to attain consolidation efficiencies early while providing assurances to customers that they will share in any long-term savings without having to wait 11 years.

What commitments to future action have the utilities made during their respective 2013-2018 rate plan terms, what other rate setting issues merit attention now(including cost allocation issues), and when and how are these commitments and issues to be addressed?

3.11 Over the past years a number of intervenors have made known concerns with the average use methodologies. In our submission the Board should have an examination of the role of average use deferral accounting if an amalgamated utility is approved.

4.0 IMPACTS OF THE MERGER

Would the proposed merger impact any other OEB policies, rules or orders (e.g. regulation of new storage, Storage and Transmission Access Rule (STAR)? If so, what are those impacts and how should the OEB address them?

4.1 As noted above VECC believes the Board should revisit the NGEIR related policies with respect to storage and transportation. The basis of the policy in now 10 years old and in any event a revisiting of its impact, success and failures would be of benefit if for no other reason than to make an assessment of its impact.

4.2 As noted above an important issue that arises from this transaction is with respect to the future of both storage and transportation contracting between EGD and Union Gas. In their evidence the Applicants stated that "[C]*ontracts that are for regulated services are cost based and will continue to be charged at cost to EGD customers. The regulated service contracts include a regulated return on investment*[5]." In our view if this is correct then it needs to be revisited since it would be difficult to say that just and reasonable rates include some Amalco customers getting the benefit of a margin from other Amalco customers. Ultimately the issue, that it is not possible for a company to contract with itself, highlights the importance of revisiting Amalco's cost allocation and rate design in the near, not long term.

4.3 The issue of storage is of particular concern. Union, Enbridge and its affiliate Market Hub Partners Canada L.P. own 99.1% of the total storage capacity in Ontario.[6] In 2018, EGD has contracted 26.4 PJ of third party storage services for which it will pay some $18.0M at an average cost of $0.68/GJ. The comparable regulated rate for this type of service is $0.3484/GJ, or a differential of $0.3316/GJ. As of April 1, 2018 EGD contracts for 19.5 PJ of storage from Union at market rates. Amalco is not proposing to convert any of this storage space from non-rate regulated.[7] Customers of Union Gas receive a net benefit in rates of $4.5 million from the sale of short-term storage and other balancing services[8].

If leave is granted, what conditions should be attached?

4.4 The one issue that we think essential for the Board to attach to its decision is in the event it decides to deny in whole or part the rate proposal of the Applicants. In this proceeding the Applicants have made the extraordinary statement that they would reconsider their application in light of less than 100% approval of their proposal[9].

4.5 Given this unless the Board is willing to comply with this demand it need consider what the two utilities will be required to do. In our submission the Board's course of action should be to require full cost of service applications for the 2020 rate year, which is the earliest year we believe a full cost of service application for both Utilities could be implemented. The Board should then declare current rates final until that time, but with earnings sharing set for both utilities at 100 basis points above Board approved.

4.6 In this manner ratepayers will be protected and until such time as a cost of service review can be completed. Such a review should, at least from Union Gas include a comprehensive cost allocation study.

[5] C-OGVG-5
[6] JT2.9
[7] C-Staff-10
[8] JT.12
[9] See Vol 1, May 3, pages 12 - 15

What is the status of the Undertakings to the Lieutenant Governor in Council of Ontario?

4.7 VECC has no submission with respect to this issue.

To the extent that the Undertakings are impacted by this application, should any of the provisions of the Undertakings be replaced by a condition of any OEB approval?

4.8 VECC's submissions with respect to conditions attached to approval are made under issue 9.

If so, what should the content of the condition be?

4.9 VECC's submissions with respect to conditions attached to approval are made under issue 9.

5.0 RATE-SETTING MECHANISM

RATE FRAMEWORK:

If the OEB grants the Applicants' request for approval of the amalgamation and deferral of rebasing, what should be the features of a Price Cap IR mechanism during the deferral period, including?

- **e) What is the appropriate inflation factor [I]?**
- **f) What is the appropriate productivity factor [X]?**
- **g) Should a stretch factor apply and if so, what is the appropriate stretch factor?**
- **h) Should there be pass through (Y factor) treatment for costs such as:**
  - **I. Gas commodity and upstream transportation costs?**
  - **II. Demand side management (DSM) costs?**
  - **III. A lost revenue adjustment mechanism (LRAM)?**
  - **IV. Cap-and-trade costs?**
  - **V. Changes to normalized average consumption/average use?**

5.1 VECC expects a number of parties to discuss the merits of the forecast cost and savings provided by the Applicants in this proceeding. In our view the difficulty is that not much weight can be given to the projections. By their own admission the costs and savings are highly preliminary and without significant detail supporting documentation. The Applicants have reiterated the fact that they will not be able to understand the true costs and benefits of this transaction until they receive Board approval and do the work as was noted in this exchange[10]:

> MR. RIETDYK: Mr. Shepherd, we have been merged, yes, since February 27th of '17, and prior to that, we weren't able to even talk to each other about the merger. Once we merged we then proceeded down the path of looking at an amalgamation under the MAADs policy, and that's what we've been focused on, and we developed a high-level business plan, a high-level plan, that would provide benefits to ratepayers based on the MAADs policy.
>
> That's what we're doing. We're now in the proceeding, and we're waiting for the Board's decision before we start to actually do the detailed planning, because that will happen, as we've said in our evidence, and in presentations to our Board. Once we have the Board's decision and we decide to proceed, we will set up a project management office and we will embark on the detailed planning, execution, and the implementation to bring those savings to customers.

5.2 There is also an inevitable unreliability to the savings number because they make certain assumptions 10 years into the future. Finally, in our view Union and EGD have both made optimistic assumptions about the starting point of their future savings. They have, it seems to us, highly optimistic views as to what based rates would be should the Board require 2018-19 rebasing.

5.3 Even if taken at face value the range in outcomes is extremely broad as shown in the table below.[11]

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[10] Vol 1, May 3, 2018, pg. 40
[11] C-Staff-3

High Level Minimum and Maximum Cost and Savings Estimate ($ Millions)

Item	Potential Capital Investment		Potential O&M	
	Min	Max	Min	Max
Customer Care	**$25**	**$110**	**$120**	**$250**
Distribution Work Management	**$10**	**$90**	**$30**	**$150**
Utility Shared Services	**$5**	**$20**	**$15**	**$50**
Storage and Transmission	**$5**	**$10**	**$15**	**$50**
Management Functions & Other	**$5**	**$20**	**$170**	**$250**
Total	**$50**	**$250**	**$350**	**$750**

5.4 In our submission the Board should factor in the high level of uncertainty in the projections of the Applicants. As noted above one way to do this is to adjust the form of earning sharing to balance incentives for finding efficiencies with sharing some of those benefits with ratepayers. As with earning sharing the issue of how rates should be set if there is an amalgamation must reflect a balance of competing objectives. In our view the use of a price cap for the period until deferment is preferable to some other options like a revenue cap. But like the ESM the form of that price cap must, in our submission, be made in consideration of the length of the deferment period. The longer the period the more stringent or cautious the Board must be in order to protect the interests of consumers.

5.5 In the proposed price cap there are four factors that need to be considered in achieving a fair balance in the price cap adjustment plan: inflation, productivity and stretch factor and the length of the plan. We have considered the last of these in other places and focus below on inflation, productivity and stretch factors.

<u>Inflation Factor</u>

5.6 We generally believe that price cap plans should use CPI as an inflator. In our view customers expect their rates to follow, or be less than, the overall rate of inflation. The purpose of the inflation factor should not, in our view, be to find the best proxy for the inflation of utility inputs. Doing so, in our minds, is circular as it provides the utility (theoretically) with 100% of the inflated cost of inputs. This reduces or eliminates incentives to reduce those costs. An input price inflator is also at odds with the underlying premise of the price cap (at least from a consumer's point of view) which is to seek to keep price increases at or below the increases faced by consumers for the wider basket of goods represented by the CPI.

5.7 Having said that, while there are year on year variations, there is little difference in the aggregate over the longer period in the inflation indices as can be seen from the table below[12]. Given that, in our view if the price cap plans is three years or less, than in the aggregate the choice of inflator is relatively immaterial.

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
	V62307283 year average (from Q1 to Q4)	GDP IPI FDD year average (%)	V62307283 annual (Q4)	GDP IPI FDD annual (%)	V41690973 year average (from Jan to Dec)	CPI year average (%)	V41690973 annual (Dec)	CPI annual (%)
2007	100.0		100.3		111.5		112.0	
2008	102.6	2.6%	103.6	3.3%	114.1	2.4%	113.3	1.2%
2009	103.7	1.1%	104.1	0.5%	114.4	0.3%	114.8	1.3%
2010	104.8	1.1%	105.5	1.3%	116.5	1.8%	117.5	2.4%
2011	107.3	2.4%	108.3	2.7%	119.9	2.9%	120.2	2.3%
2012	109.1	1.7%	109.6	1.2%	121.7	1.5%	121.2	0.8%
2013	111.0	1.7%	111.7	1.9%	122.8	0.9%	122.7	1.2%
2014	113.5	2.3%	114.3	2.3%	125.2	1.9%	124.5	1.5%
2015	115.4	1.7%	116.2	1.7%	126.6	1.1%	126.5	1.6%
2016	116.8	1.2%	117.5	1.1%	128.4	1.4%	128.4	1.5%
2017	118.4	1.4%	118.9	1.2%	130.4	1.6%	130.8	1.9%

Productivity Factor

5.8 Both experts in this proceeding agree on the application of a 0% productivity factor. We accept the consensus results.

5.9 As we understand Board Staff's queries and potential objections to methodological (rather than outcome) the issue of concern how these methodological differences, if accepted, might impact other proceedings. We have no opinion on that matter as we are somewhat wary of the spurious accuracy implied by all such studies and irrespective of the methodology employed.

Stretch Factor

5.10 In L1.VECC.1 we asked for clarification from Dr. Makholm around the following statement made in his evidence:

> The AUC made three important determinations regarding the stretch factor that I conclude are reasonable:(1) it does not have a "definitive analytical source" like a TFP growth study, but relies on a regulators' judgment and regulatory precedent; (2) it has no influence by itself on the incentives for regulated companies to reduce costs; and (3) it serves to reflect the "immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

[12] C-VECC-26

5.11 In the response to this interrogatory and in the following discussion which took place at the hearing[13] Dr. Lowry, the expert employed by Board Staff , had a difference of opinion on the applicability of a stretch factor. As we understand that difference it has less to do with items (1) and (2) and more to do with item (3). That is, Dr. Lowry provides a nuance in his discussion in linking stretch factors with benchmarking. But the fundamental disagreement is whether a stretch factor only serves to address the immediate transition from cost of service to some other form of incentive rate making. Dr. Makholm says that that is its sole purpose whereas Dr. Lowry says that the stretch factor has a broader incentive purpose.

5.12 In our submission the Board should adopt the opinion of Dr. Lowry and adopt a stretch factor of 0.30%. We think there are two compelling reasons to do this. The first is that despite the application evidence, interrogatories and lengthy cross-examination on the issue VECC can find nothing which supports the view that the sole purpose of a stretch factor is to anticipate productivity arising from the introduction of incentive rate making[14].

5.13 In fact, such a proposition argues against the first tenant adopted by Dr. Makholm that the adoption of a stretch factor relies on the regulators judgement.

5.14 Besides much of the argument put forward from Dr. Makholm and most of the re-examination of Dr. Lowry by the Applicant on this issue rests on the findings of the Alberta Utilities Commission[15]. For all intent and purpose the Applicant and their expert have put forward the idea that the Ontario Energy Board should adopt holus-bolus the findings of another regulator. And not just in a different jurisdiction but in response to a wholly different type of proceeding – one that had nothing to do with a proposal to amalgamate or to defer cost of service rate making for 15 years. In our submission it is preposterous to ask the Board to substitute it assessment of the facts before it with a sprinkling of evidence from a proceeding in another jurisdiction and adopt their findings.

5.15 On the facts before it the evidence is that a stretch factor has the purpose of embedding expected productivity savings – plain and simple. It is within the Board's judgement as to how (or whether) to apply a stretch factor in consideration of at least the Applicant's advertised productivity savings that will occur as part of an amalgamation.

5.16 However, it is not just the expected productivity savings that need to be considered. It is also those that we know are embedded in the Utilities as the result of the incentive rate plans they have been under over the past 5 years. And these may be significant.

[13] Vol 4, May 15, 2018, pages 7-25 (Makholm) and pages 150- (Lowry)
[14] Whether that "transition" takes place over one or more IRM periods is of little consequence to our argument.
[15] See Volume 4, May 15, pages 166-

5.17 Below we have reproduced the actual (non-weather normalized earnings of both Utilities. What this shows is but for one year (2016 EGD) the two Utilities have managed to exceed the expected earnings implied by the rates charged[16].

EGD Earning Sharing Results

Year	Ratepayer Share of ($Millions)	Gross Normalized Over Earnings (Above Allowed ROE + ($Millions)	Achieved ROE %	Normalized Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance
2008	5.60	11.20	11.87%	10.21%	8.66%	1.00%	50%/50%	EB-2009-0055
2009	19.30	38.60	12.36%	11.20%	8.31%	1.00%	50%/50%	EB-2010-0042
2010	17.35	34.70	10.25%	11.10%	8.37%	1.00%	50%/50%	EB-2011-0008
2011	14.30	28.60	10.43%	10.38%	7.94%	1.00%	50%/50%	EB-2012-0055
2012	7.39	14.80	7.62%	9.28%	7.52%	1.00%	50%/50%	EB-2013-0046
2013	-	31.20	11.13%	10.41%	8.93%	N/A	N/A	No ESM
2014	12.65	25.30	12.39%	10.46%	9.36%	0.00%	50%/50%	EB-2015-0122
2015	6.45	12.90	10.41%	9.82%	9.30%	0.00%	50%/50%	EB-2016-0142
2016	3.40	6.80	8.76%	9.42%	9.19%	0.00%	50%/50%	EB-2017-0102
2017	23.55	47.10	9.71%	10.27%	8.78%	0.00%	50%/50%	Preliminary results

Union Earning Sharing Results

Year	Ratepayer Share of ($Millions)	Gross Over Earnings (Above ROE + ($Millions)	Achieved ROE % (1)	Allowed ROE %	Threshold / Deadband %	Ratepayer / Shareholder Sharing Ratio %	ESM / Deferral Clearance
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.

[16] VECC Undertaking J2.3

5.18 We know these embedded savings are significant. Below we have reproduced the actual (non-weather normalized earnings of both Utilities. What this shows is but for one year (2016 EGD) the two Utilities have managed to exceed the expected earnings implied by the rates charged[17].

5.19 Only one of two conclusions can be drawn from the consistent overearning under the prior IRM plans. Either the Utilities "pulled one over" by overestimating base year costs or, more likely they were able to find long-term and sustainable savings. While some of these productivity appear to be non-sustaining as witnessed by the decline in the overearning margin the continued and systemic overearning suggests that at least to some extent they continue on today. That fact is clear from the ability of the current rates to continue to exceed the Board's allowed rates of return.

5.20 In arguing against the inclusion of a stretch factor, the Applicants have suggested that it would add $410 million to their required savings to be found. But since the forecast of costs and savings of the amalgamation is, by the Applicant's own admission, highly variant at this point, it seems to us this is not the question the Board should be considering. In our view what should be considered are the historical returns and the stated returns that are needed to make this transaction attractive to the Applicant. Those returns are clearly outlined and were discussed at length in the hearing[18].

	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%

5.21 We make two observations from this table. The first is that the needed achieved ROE is very close to the weighted actual ROEs of the two utilities in 2017. We also know that some long-term productivity initiatives, most notably, large FTE reductions at EGD have yet to be imputed in the actual ROEs achieved and in fact, due to severance costs have "artificially" reduced returns in 2015 through 2017[19]. It follows from that that the current rates support the ROE targets of this transaction.

5.22 The second is that the spread between the Board's allowed ROE and the desired achieved is between 20 and 30 basis points. History of returns of the two Utilities would suggest it is highly unlikely that the past overearnings are unsustainable even under current rates.

[17] VECC Undertaking J2.3
[18] C-Staff-4
[19] See JT1.17 which shows EGD estimated annual savings and gross severance costs.

Y factor/ Pass-Through/DSM/LRAM/NAC

5.23 VECC has a concern with the continuation of the Normalized Average Use/Consumption Accounts (NAC). In other proceedings the issue of the calculation used for these accounts has become an issue. There is also the fact that the accounts are similar, but not identical in their calculation. The two utilities have developed and implemented unique forms of the accounts as part of different rate plans.

5.24 Our other concern is that there is currently no direct linkage between the demand side management activities (DSM) of the utilities and NAC adjustments. This would seem odd given that these NAC related adjustments notionally address the issue of the consequence of utility sponsored DSM. This seems to us this is quite different than the Board's LRAM policies which draw a direct relationship between the conservation program and the associated decline in energy use. Given the Applicant's appetite for adopting Board electricity policy we think the lack of any proposal to bring convergence between DSM and CDM policies in this application is striking.

5.25 The NAC accounts remove load or consumption risk by applying a trend factor to the variable portion of the rates. To the extent that distribution costs are recovered via a fixed component of rates both NAC and the electricity LRAM protections are not required since revenues are decoupled from energy consumption. Decoupling is Board policy in electricity. VECC has serious reservations about the value of decoupling especially with respect to its impact on low-income consumers and because of its antithetical conservation effect. Yet, again, here again, while the Applicants have picked up the tenuous relationship with electricity for consolidations, the more obvious issue of decoupling in gas rates is ignored in this application.

5.26 Furthermore NAC accounts, unlike LRAM policies, also protect gas utilities against "natural conservation" or general declines in gas consumption due reasons other than DSM programs. No distinction is made in providing consumption risk protection to the utility and no rationale is provided as to why electricity consumers are subject to a different scheme which does not protect against general declines in the consumption of electricity. Certainly we understand the desirability of NAC accounts from the perspective of the Applicants who want a 10 year hiatus from cost of service ratemaking. It is less clear to us why the Board would allow for Ontario natural gas consumers to be subject to one set of principles with respect to the impact of conservation and energy trends and electricity consumers to be subject to a different one. In our submission there are no obvious reasons as to why the principles of both should not be the same. For this reason we believe both that the NAC accounts should not carry forward past 2018 and that the Board should convene a proceeding to examine the issue of NAC/DSM to ensure it adheres to the same principles as electricity LRAM/CDM.

Should there be a Z factor, and if so what are the appropriate parameters and materiality threshold?

5.27 VECC submits the proposed z-factor materiality threshold of $1 million is patently too low. It is in fact lower than the current materiality thresholds of $4.0m and $1.5m of Union and EGD respectively[20].

5.28 The Applicants have, again selectively chosen from the Board's electricity distribution sector policies. However, those policies were clearly developed in light of the large number of small utilities and the small number of large utilities. Amalco would far outsize any of the electric distributors. The only utility that would come close to size in terms of revenue requirement is OPG. It is our understanding that an equivalent materiality threshold for OPG would be in the order of $10 million.

5.29 Other than the adoption of a policy clearly not intended for a large utility, there was no other rationale presented why the materiality thresholds of Union and EGD should not be the same as the combined number of the two or the combined of the higher of the two. Therefore in our submission the Board should set the z-factor threshold at between $5.5 and $10 million.

Should there be an earnings sharing mechanism and if so what are the appropriate parameters?

5.30 We have made detailed submissions on ESM above. Here we would just note again the response to this question depends on the Board's determination of the ratemaking plan it is prepared to approve and the period for which the Utility will be allowed to have its rates diverge from the underlying costs and allocation of those costs. In our view the longer the rate rebasing deferral the more aggressive needs to be the earning sharing. In our view this is just common sense. The longer the deferral the more uncertain the outcomes. Since the Utility has the opportunity to apply to the Board at any time the risk involved in that uncertainty is asymmetric. If earnings are excessive the Applicant is unlikely to seek permission to lower rates, whereas the opposite is true.

5.31 We also note that the Board made this determination with respect to the application of earning sharing[21].

> If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

[20] C-Staff-23
[21] Handbook for Utility Rate Applications, October 13, 2016, page 28

5.32 In our view the longer the deferral period granted by the Board the more important is the view that the earning sharing mechanism needs to consider the overall earnings throughout the term and not just at some arbitrary point within the term

Is the proposal for calculating the cost recovery treatment of qualifying capital investments consistent with the OEB's policy for Incremental Capital Modules, and if not are any deviations appropriate?

5.33 To the extent that future ICM projects are for discrete large activities that fall outside the normal capital planning the Board's electricity policies would provide ICM relief. We believe the same principles should be applied in the gas sector. We also note that in response to C-Staff-27 the Applicants have stated that "

> In support of any ICM proposal, Amalco will file its Utility System Plan which includes an Asset Management Plan. For 2019, Asset Management Plans for Union South and Union North will be separate from the Asset Management Plan for EGD. Over the deferred rebasing period, Asset Management Plans will be combined but will retain the ability to identify the affected rate zone.

5.34 However, a significant deficiency of this application with respect to ICM/ACM policies is the lack of a comprehensive distribution system plan as supported by a robust asset assessment. The Board's electricity policies in this regard have developed out of many years of experience in having electricity distributors submit for review such plans. In this preceeding both Utilities filed its first Asset Management Plans as required by the Filing Requirements for Natural Gas Rate Applications. Neither resembles a distribution system plan or asset assessment report generally provided by an electricity distributor. Neither plan lays out a comprehensive future capital plan (the typical is 5 years) nor do either include a methodological based assessment of the condition of utility assets.

5.35 To some extent there are difficulties because the Board's nomenclature of Utility System Plan and Asset Management Plan are different than the electricity sector's Distribution System Plan and Asset Assessment Report. While VECC assumes the Board's purpose in demanding system asset information is similar in both sectors we admit it is not clear from a reading of the Natural Gas Filing Guidelines that the Board is seeking to apply uniform principles in both sectors. In any event, these are matters likely to be worked out in a future cost of service application and another reason to resist a 10 year deferment.

5.36 In our submission if the Board approves the rate plan in any form, it should provide direction with respect to its expectations on a system wide and comprehensive distribution plan and asset assessment report. If the rate deferment is less than 4 years we believe this could be done at the time of the first comprehensive rate rebasing.

5.37 The Applicants also propose a means test which uses a 300 basis point excess earnings as the cap for the means test.[22] In our submission this should be reduced so that the Utility is not eligible for ICM approval if returns are in excess of 100 basis points of the Board approved figure. In our view ICM type capital expenditures should not be used as a means of increasing revenue requirements during any deferred rebasing period. A lower threshold would serve to protect consumers from excessive or "gold plated" rate base increases during the term of the plan.

How should the framework address the four objectives in the Renewed Regulatory Framework of customer focus, operational effectiveness, public policy responsiveness and financial performance?

VECC has no submission to this question

What changes to rates, regulated services, cost allocation or rate design should be permitted or required during the deferred rebasing period and what process should be required for such changes to be made?

Our submissions on this issue are made in section 5 above

What should the annual rate adjustment process be?

VECC has no specific submission on this issue

What deferral and variance accounts should continue?

VECC has made its submission on deferral accounts above

What deferral and variance accounts should not continue?

VECC has made its submission on deferral accounts above

What additional deferral and variance accounts are appropriate?

VECC has made its submission on deferral accounts above

Is the proposed adjustment to reflect the full amortization of Union Gas' accumulated deferred tax balance at the end of 2018 appropriate?

VECC has no submission to this question

Is the proposed adjustment to unwind smoothing of costs related to Enbridge Gas' Customer Information System and customer care forecast costs appropriate?

VECC has no submission to this question

Is the proposed adjustment to Enbridge Gas' Pension and OPEB costs appropriate?

VECC has no submission to this question

[22] C-Staff-28

Is the proposed adjustment to reflect the removal of Enbridge Gas' tax deduction associated with the discontinued SRC refund appropriate?
VECC has no submission to this question

6.0 OTHER

Are the provisions of the MAADs Handbook related to harmonization applicable?

6.1 As noted above VECC takes the position that the Handbook to Electricity Distributor and Transmitter Consolidations, 2016, is not applicable to the Gas sector. In any event the provisions of the Handbook contemplate rate harmonization. In passing we do not believe the 10 year deferral of cost allocation and rate design for any consolidating distribution utilities meets the test of "just and reasonable."

6.2 We would refer the Board to VECC undertaking J2.2 which compares the rates and rate structures of Union Gas (North and South Zones) with EGD. This shows that from the time of amalgamation similar situated customers will face very dissimilar rates. In other places we have made the argument that inter and intra class inequities will result and become worse over time undermining the premise of a just and reasonable rate.

How should past OEB directives and utility commitments be addressed?
VECC has no submission on this issue

Is the proposed scorecard appropriate?

6.3 At C-Staff-62 the Applicants provided the historical results of their proposed scorecard. The metrics within the scorecard are innocuous and follow in larger part either prior scorecard metrics and those used by electricity distributors. As such we have no objections.

6.4 However, we find it odd that given the prolonged rate rebasing deferment proposed the scorecard has no means of gauging customer satisfaction with either rate structures or the rates themselves. This does not seem to fit with the Board's recent focus on customer engagement.

6.5 Minimally we would expect the Board to want to gather data on the concerns of customers with respect to rate impacts. We would also expect the Board to want to understand from what parts of the former franchise these complaints might emanate in order to understand whether there was dissatisfaction with the new amalgamated utility's operations in particular regions.

6.6 We are the first to admit this issue was not broadly canvassed in this proceeding. In our submission if the Board is inclined to approve a 10 year rate deferment then it should strike a stakeholder exercise to hone a more applicable scorecard which would allow the Board to better monitor customer satisfaction with the amalgamation.

What reporting should be required during the deferred rebasing period?

As VECC supports a shorter deferred rebasing period than proposed by the Applicants. The reporting requirements we support are made below.

What stakeholder engagement should be required during the deferred rebasing period?

6.7 VECC submits the following exercises should be undertaken over the next 5 years:

- Review of STARR/NGEIR
- Review of the QRAM process/ Gas Supply Plans of Amalco
- Stakeholdering of future cost allocation/rate design for Amalco
- DSM/LRAM/NAC Review of the appropriate rate making integration for the impacts of demand management and other greenhouse policies on utility revenues.

7.0 CONCLUSIONS

7.1 In making our submissions VECC considered these questions:

- Does the utility have a reasonable opportunity to recover any costs for post amalgamation productivity initiatives?
- Do consumers have a reasonable opportunity to share in any economies arising out of the amalgamation.
- How long will the current rates (as annual adjusted) fairly represent the underlying allocation of the costs of service?
- Are there issues with respect to the current rates, demand side management, and storage & transportation services that need to be addressed in the short to mid-term horizon?

7.2 While we have recommended a rate rebasing period for a period of no more than 4 years we recognize that the Board could find a shorter or longer period acceptable. In our view a period longer than 6 years would likely mean that there are significant inter and intra cost misallocations that would arguably result in unjust and unreasonable rates.

7.3 VECC believes the Board should approve the amalgamation transaction provided certain proceedings are undertaken within the first four years of the approval (as set out in section 6).

7.4 In our submission the rate plan should not be modified to be no longer than four years and to be followed by an amalgamated utility cost of service rate application. This application should include a proposal for rate harmonization and a new comprehensive and utility wide cost allocation study.

8.0 COSTS INCURRED

8.1 VECC respectfully submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED