NB:

"PEG Study" refers to the document: IRM Framework for the Proposed Merger of Enbridge and Union Gas, April 11, 2018. Exhibit M1

"Dr. Makholm evidence" refers to Expert Report and Direct Testimony prepared by Jeff D. Makholm, PH.D, National Economic Research Associates Inc. Exhibit B, Tab 2

L1.VECC.1

Reference Exhibit M1, page 3

The following statement is made (referenced) in Dr. Makholm's 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."

a) Does PEG agree that the above statements regarding the stretch factors are reasonable? Does PEG have any qualifications it would make with respect to any of the three factors listed?

Response: The following response was provided by PEG.

a) For the most part, no. Dr. Lowry believes that, to establish stretch factors, statistical benchmarking studies of cost performance can be undertaken which use theoretically and statistically sound methods and have a degree of accuracy that is comparable to that of TFP growth studies.

   Dr. Lowry acknowledges that less research has been done to date to determine how stretch factors (or initial revenue requirements) should be linked to benchmarking studies. In past proceedings, he has based X factor recommendations on incentive power research that addresses the extent to which the proposed IRM is expected to stimulate more rapid TFP growth than the regulatory systems of firms in the productivity study. However, considerably larger adjustments could be argued on different grounds, such as the ability of stretch factors to strengthen performance incentives, discourage strategic cost deferrals, relieve customers of the unfair burden of paying for inefficient operations, and to reward superior cost management.

With regard to the second point, Dr. Lowry believes that if stretch factors are linked to cost performance, as they usually are in Ontario, they do affect utility performance incentives. A cost-level benchmarking study could be part of a rebasing exercise. The Applicants should be expected to file a benchmarking study in future rebasings.

With regard to the third point, Dr. Lowry does not agree that stretch factors are only appropriate in first generation IR. Please see PEG's response to EGD/Union.2 for further discussion.

L1.VECC.2

Reference:

a) The Applicants have forecast future efficiencies arising out of the proposed amalgamation. In PEG's view how these efficiencies should be incorporated in the PCI rate adjustment formula?

Response: The following response was provided by PEG.

Dr. Lowry notes that the Applicants seek supplemental funding when the need for capex is expected to be high but do not propose to share with customers expected benefits of their merger for five years. The proposed ratemaking treatment of mergers is taken from OEB merger guidelines intended to encourage consolidation of a provincial power distribution industry that has numerous small utilities and high regulatory cost. Gas distribution service territories in Ontario are not balkanized and, with only two large distributors to regulate, the cost of regulation is reduced. In the United States, the ratemaking treatment of mergers often involves extended rate freezes that implicitly share expected merger benefits with customers at the same time that they incentivize cost savings and reduce regulatory cost. A good example is the four-year base rate freeze that accompanied the merger of NSTAR and Northeast Utilities in Dr. Makholm's home state of Massachusetts.[1]

Customers of the Amalco can then reasonably complain about the asymmetric treatment of favorable and adverse business conditions in the Applicants' proposal. Dr. Lowry discussed this general problem in Section 7.3 of his report. One solution discussed there is to raise the X factor. The AUC stated in its decision in its first generic IR proceeding that

> The Commission agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism.[2]

[1] Massachusetts Department of Public Utilities, 10-170-B, *Joint Petition for Approval of Merger between NSTAR and Northeast Utilities, pursuant to G.L. c. 164, §96, pp. 18-19, 41.*

[2] Alberta Utilities Commission, Rate Regulation Initiative, Distribution Performance-Based Regulation, Decision 2012-237, September 12, 2012, p. 96.

L1.VECC.3

Reference: PEG Study, page 4

a) Please explain more fully why "*skipping a rebasing in 2019 will do little to spur the Applicants' incentives.*"

Response: The following response was provided by PEG.

a) If the merger had been approved in the first year or two of the Applicant's current IR plans, knowledge of an extended period without rebasing would have materially strengthened the company's performance incentives for four or five years. Programs involving upfront costs and long-term performance gains would have been greatly encouraged. In year five of the IR plan, however, only one year of operation undertaken in the knowledge of an imminent rebasing would be avoided. Furthermore, the rebasing can in principle be undertaken based on costs incurred before 2018 to avoid weakening performance incentives and having to address merger costs and benefits. See, for example, the rebasing of OM&A revenue that the AUC approved for Alberta energy distributors in Decision 20414-D01-2016.

L1.VECC.4

Reference: PEG Study, page 14

Preamble: As noted by the PEG authors the Applicants propose continued use of a normalized average consumption (NAC) adjustment which has the effect of reducing risk of under-recovery of costs. PEG also points out (page 26) that "[T]*his is clearly the main reason for the slowing growth in NERA's TFP indexes after 2000, but has limited relevance to the calibration of an X factor for the proposed IRM of the Applicants*."

a) If the Board choses to eliminate the NAC adjustment going forward how do the authors believe this should impact the price cap adjustment formula?
b) If the Board choses to continue the NAC adjustment and given the Author's conclusion that the NAC adjustment reduces risk to the utility - might this reduction in risk reasonably be expressed in the price cap adjustment in any other manner than the adjustment proposed by the use of number of customers in supportive TFP calculations (page 53)?
c) Given the current recommendation of the Author for use of a 0% X-Factor is it likely that the adoption of customer numbers in the TFP make any material difference to the X Factor used in the PCI formula?

Response: The following response was provided by PEG.

a) In the absence of a NAC, the X factor might have to be calibrated to reflect the average use trends of residential and general service customers. This could be done by considering the trend in TFP indexes designed to capture average use trends. Alternatively, the base TFP trend could be adjusted for the expected trend in the average use of the Applicants' general service customers.
b) In the United States, declining average use is sometimes addressed by revenue per customer decoupling. The utility is protected from all sources of demand variation. These mechanisms have in some states been combined with a modest (e.g., 50 basis point) reduction in the allowed ROE. The NAC also reduces risk, but the impact is lessened by the weather normalization provision.
c) Not if there is a single rate or revenue cap index. The X factors could be affected if the Board were to embrace separate ratemaking treatment for OM&A and capital revenue, as discussed in PEG's response to SEC-5. Note also that adoption of this method now could raise X factors in future plans if the method continues.

L1.VECC.5

Reference: PEG Study, page 17-25-

Preamble: PEG notes a number of deficiencies with the Ma study, including the use of OHS (as opposed to GD) for the capital quantity measurement and lack of gas utility data in the study and the exclusion A&G costs. Numerous other concerns are set out at pages 25 through 37. At page 36 the sum of corrections (using OHS) appears to be a TFP trend of +0.85%. Nonetheless the PEG study authors conclude that "t*he 0% base TFP growth trend that Dr. Makholm proposes is in our view reasonable*." (page 2)

a) How is this conclusion reached in light of the various deficiencies identified with the Makholm Study?
b) Why would an x factor of 0.49% (page 48) not be more appropriate?

Response: The following response was provided by PEG.

a) The +0.85% TFP trend using PEG's upgrades to NERA's methodology is for an unusually lengthy sample period that may not reflect the long-run TFP trend. The 0.49% trend for the 2001-2016 period is probably more pertinent. However, Dr. Makholm's study addresses the TFP trend of power distribution, not gas utilities that provide transmission, storage, and customer care services in addition to gas distribution services. Dr. Lowry reports a cost efficiency trend of only -0.39% for US gas utilities. The 0.0% base productivity trend that he proposes if there is consolidated indexing of OM&A and capital revenue is well above this.

b) Please see the response to VECC.5 a.

L1.VECC.6

Reference: PEG Study page 43

a) PEG has found that Enbridge and Union have TFP growth trends which are diametrically opposed (negative and positive respectively). Given that under an amalgamated there are proposed to continue to be two separate rate zones might it be reasonable, Author's opinion for two separate X factors to be applied to each rate zone? Please explain why or why not.
b) In the same vein, might different stretch factors be applied to the two rate zones? If so how might these be set?

Response: The following response was provided by PEG.

a) This proceeding has not provided an evidentiary record for separate base productivity trends.

b) Cost-level benchmarking studies are unavailable that would provide the basis for separate stretch factors for the EGD and Union rate zones.

L1.VECC.7

Reference: PEG Study, page 37

a) The authors note that U.S. mandated safety programs had a material impact on total factor productivity growth. Given this, why is appropriate to apply the conclusions of PEG`s US Gas Distributor study to the proposed Ontario Amalco?

Response: The following response was provided by PEG.

a) Please see our response to SEC-1.