ONTARIO ENERGY BOARD

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

Industrial Gas Users Association (IGUA)

Argument

INTRODUCTION

1. It is IGUA's general view that utility shareholders should be free to structure their utility ownership as they see fit, as long as ratepayer interests are not unduly compromised thereby. This is, in essence, a "no harm" approach.

2. It is IGUA's further view that such structural freedom, including in particular the freedom to consolidate, should foster efficient and cost effective utility services, ultimately to the benefit of ratepayers.

3. The Board's "no harm" test focusses on; i) expected post-merger cost structure (as it will likely impact rates); ii) the post-merger adequacy, reliability and quality of utility service; and iii) the likely impact of the proposed transaction on the financial viability of the post-merger entity.[1]

4. IGUA foresees no harm from, indeed expects benefits for ratepayers from, the proposed merger *per se*, and supports approval of the merger by the OEB.

5. IGUA's concerns with the proposals advanced by EGD and Union (together Applicants) in this proceeding arise in connection with an extended rebasing deferral. In the views of

[1] Handbook to Electricity Distributor and Transmitter Consolidations, pages 6 through 8.

IGUA's members, 10 years is far too conservative an assumption of the time it will take to realize merger efficiencies. In their own businesses they have never encountered time horizons like that (and these are very large businesses).

6. In the instant circumstances, what is posited as a 10 year deferral of rebasing (from 2019 to 2029) would actually result in a period of more than 15 years between the resetting of rates to reflect costs to serve. The cost forecasts on which each of EGD's and Union's current rates have been determined were made prior to 2013. Deferring rebasing of rates for another 10 years would result in the passage of an unprecedented amount of time between full examination of the costs to serve Ontario gas distribution customers.

7. IGUA does believe that barriers to shareholder investments reasonably required to realize efficiencies should be removed. IGUA further endorses provision of reasonable incentives to encourage utility shareholders to make such investments. However, IGUA opposes what is effectively a 15 year hiatus on a balanced sharing with ratepayers of efficiency benefits – both those realized in the 5 years now ending and those to be realized in the coming years as a result of the planned merger.

8. IGUA further notes that rates are not planned to be "flat". The utilities anticipate passing through material capital investment costs along the way, and IGUA fully anticipates material upward rate pressure in the coming years. Effectively withholding ratepayer benefits despite such material upward rate pressures is not appropriate.

9. IGUA's concerns are exacerbated due to the lack of any reasonable productivity expectations embedded in the proposed rate setting framework. Productivity is presumably the whole point of the initial acquisition of Spectra/Union by Enbridge Inc., and is an express justification for the proposed merger of the utilities.

10. Experts have testified in this proceeding that productivity is expected when regulated utilities move from cost of service to an incentive based rate framework. Surely efficiencies are also to be expected when two large utilities merge on the premise of realizing efficiencies.

11. The proposed rate setting framework is missing a reasonable mechanism for reflecting both historical productivity achievements and ongoing productivity expectations in rates.

CONCERNS WITH PROPOSED REBASING DEFERRAL

12. The Applicants appear to maintain their position that the Board's *Handbook to Electricity Distributor and Transmitter Consolidations*, January 19, 2016 applies to the proposed merger and that policy allows the Applicants to select a 10 year rebasing deferral.[2]

13. In Procedural Order No. 3 herein the Board has already ruled on this assertion, and has rejected it[3]:

> *The OEB does not agree with the arguments of the applicants and accepts the position of the intervenors and OEB staff that all aspects of the MAADs Handbook do not automatically apply to natural gas. The MAADs Handbook does not specifically reference natural gas and there is no specific guidance in the Handbook as to how gas mergers should proceed. The OEB is of the view that issues such as the deferral period and earnings sharing mechanism are legitimate areas of inquiry and are not pre-determined in this case.*

14. Given that the Board has already clearly ruled on this issue, we will not repeat IGUA's arguments previously filed in this respect. To the extent that there is still any legitimate debate about the Applicants' assertions in this respect, we repeat and rely on IGUA's January 26, 2018 submissions on the EB-2018-0306 issues list.

15. The issue at hand is whether the Board should allow a rebasing deferral, 10 years or otherwise, and if so under what conditions. The essential argument in favour of a rebasing deferral is that it allows the consolidated entity to invest in, and realize, efficiencies and associated savings, and those savings can;

    (a) cover the costs of consolidation and efficiency investment (thereby removing a barrier to pursuing consolidation and efficiency investment); and

    (b) in addition to removing barriers to such investments, provide an incentive to the shareholder to pursue such investments by allowing retention of resulting cost savings for some amount of time before turning the benefits of sustainable efficiencies thereby realized back over to ratepayers.

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[2] Argument in Chief, paragraphs 30 - 37.
[3] Procedural Order No. 3, page 6.

16. While IGUA supports these objectives, in the instant circumstances a rebasing deferral, and in particular an extended one, prompts a number of concerns.

17. First, both EGD and Union have been over earning over the last 5 years, yet neither proposes sharing any realized efficiencies with ratepayers as previously promised. More particularly:

(a) Both EGD and Union last rebased on forecasts developed in 2012, based on cost structures that are now 6 years old.

(b) Both gas systems have changed significantly in the past 5 years, through major capital additions/system enhancements. These capital expenditures have put significant upward pressure on gas delivery rates.

(c) While recovering the costs of intervening capital additions, both Union and EGD have benefited financially under their current IRM plans as evidenced by the fact that they have, throughout the 5 year terms of their respective plans, consistently earned in excess of the Board approved ROE (i.e. "over earned").[4]

(i) In Union's case, this despite an embedded productivity expectation of $4.5 million annually as set in its 2013 IRM settlement, <u>plus</u> a built in formulaic productivity expectation of 60% of inflation.

(ii) In EGD's case, this despite efficiency expectations embedded in the 5 year rate approvals forming EGD's Custom IR plan ending this year.

Neither of the applicants propose to return any of these efficiencies to ratepayers now, proposing instead to roll them forward for each of 10 more years.

(d) This was not the deal.

(i) Union committed in the settlement agreement in support of is current incentive rate making (IRM) plan to file a cost of service application (whether or not it requested rate setting on that basis) for 2019, and the Board ultimately accepted that settlement agreement in support of approval of Union's current IRM plan.

(ii) EGD made a similar commitment during the hearing for approval of its current Custom Incentive Rate IRM plan, which commitment was also accepted by the Board in approving EGD's current plan.

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[4] Exhibit J2.3.

Both EGD and Union have ignored these commitments/directions, and neither has addressed why their disregard for these commitments, and ensuing Board directions, should be sanctioned.

18. Second, this application entails the biggest regulatory "ask" in Ontario's history, and in this context the Board is being asked to essentially refrain from cost of service oversight for the next decade.

(a) Both applicants are larger, on their own, than any Ontario electricity distributors, both by customer numbers and by revenue requirement. Together, they will form the largest gas utility in Canada and the 2nd or 3rd largest on the continent.[5] The Board is in this application as framed being asked to approve $25 billion worth of revenue requirement, the largest monetary approval request in the history of Ontario regulation and one which would persist for a decade. Caution is warranted. Fifteen years between rebasing rates to ensure that they reasonably reflect costs to serve is not a cautious approach.

(b) The Applicants themselves stress that they need a 10 year deferral of full cost review given scale and complexity of the undertaking which they have proposed. These same considerations – scale and complexity – and the currently self-admitted preliminary plans and significant unknowns, all militate <u>against</u> an additional 10 year hiatus (for 15 years in total) in re-setting rates to reflect underlying cost to serve.

(c) Together as Amalco, the Applicants are not planning to earn only a just and reasonable return on investment. Rather they are <u>planning</u> to <u>over</u>-earn on a just and reasonable return by, on average, 20 basis points annually. This after paying for all of the efficiency driving investments brought forward at this time and assuming no additional efficiencies in the coming decade beyond those forecasted and represented as part of this application.

(d) The utilities' proposal is asymmetric in its allocation of risk over the proposed (overall) 15 year hiatus from cost of service review. If things go better than represented in the current forecasts no adjustments are contemplated. If things go poorly, Amalco will without doubt be back.

19. IGUA urges the Board to pause and consider the purpose of incentive regulation as has been adopted in Ontario, and elsewhere. It is not to give the utilities a blank check, or a decade long free pass. Rather it is to set reasonable expectations regarding costs to serve and associated rates, and then to apply a rate adjustment model that provides <u>additional</u> incentives to realize incremental efficiencies by allowing successfully reduced (from

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[5] Transcript Volume 2 (Friday May 4, 2018), page 22, lines 25 to 27.

reasonable expectations) costs to accrue benefit to the utility shareholder for a time before requiring that the benefits of such efficiencies be returned to ratepayers.[6]

20. The Board has, in the case of electricity distributors in the province, developed an enhanced version of these basic IRM principles specifically in order to encourage consolidations that were not otherwise occurring, and on a much smaller scale. In the instant case, EGD and Union are already affiliated, and the scale of the proposed rate plan is unprecedented.

21. Further, the Applicants in this case have proposed a rate plan that is singular in recent history in respect of favourability to the shareholder of merging utilities. Energy Probe filed a report in these proceedings[7] in which the authors, both well versed in energy utility regulation[8], reviewed 29 regulatory commission decisions approving utility consolidations, and found not one instance in which the outcome was as favourable to the utility shareholder as the Applicants have proposed it to be in this proceeding.[9] Having reviewed all recently approved North American utility merger decisions reported, Messers Ladanyi and Yauch shared their observations that this Board would be unique if it were to approve a merger on the terms proposed in this case.[10]

22. Regulated utilities are <u>expected</u> to be efficient, and <u>obligated</u> to be prudent. In Ontario, this has been characterized as an ongoing expectation for "continuous improvement". Given the current (pre-merger) co-ownership of EGD and Union, expectations of synergistic benefits should be the starting point for analysis of what rate setting mechanism is appropriate, and what further efficiency potential merits some reasonable incentive.

23. In this application EGD and Union are not proposing that rates be set based on expected costs. They are not proposing to consider expected costs at all.

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[6] Transcript, Volume 5, page 58 line 19 through page 59, line 11.
[7] *Review of Regulatory Decisions on Applications for Approval of Utility Mergers and Acquisitions in North America*, Tom Ladanyi and Brady Yauch, April 11, 2018.
[8] See Author's CVs attached to Energy Probe's report, as discussed at Transcript Volume 5, pages 64 to 65 and 74 to 75.
[9] Transcript Volume 5, page 82, lines 8 to 19.
[10] Transcript Volume 5, page 83, lines 13 to 17.

24. What is being proposed in this application is a hiatus on cost of service regulation for 10 years beyond the previously agreed to and directed cost reset dates, notionally in order to fund and incent utility investments to realize merger synergies ultimately to the benefit of ratepayers. At the same time, and net of all expected costs, the utilities are;

(a) planning to over earn by 20 basis points for the next decade; and

(b) proposing to share only overearnings above 300 basis points and only commencing in 2024 (which is not really much sharing at all).

25. SEC's final argument has provided some reasonable assumptions and associated calculations which illustrate an even broader range of potential consequences which the Board, on behalf of ratepayers, is being asked to accept. The "risks" that ratepayers are being asked to accept through a 10 year rebasing deferral and the lack of any meaningful sharing of efficiency benefits during such deferral extend into the billions of dollars.

26. In IGUA's view the attendant risks to ratepayers, in the circumstances summarized above, are too great, and the potential benefits to the Applicants' shareholder too rich.

27. Given the 5 years of "decoupling" of rates from actual costs now past, the addition of another 10 years before rebasing rates to more closely reflect costs to serve could result in rates in the interim departing significantly from underlying costs to serve. At some point the difference between rates and cost to serve could render rates no longer "just and reasonable".

28. Robust earning sharing (which is not what the Applicants have proposed) could address this divergence for some amount of time, through after the fact "true ups" as between shareholders and ratepayers.

29. However, there comes a point where the difference between rates and actual costs is too great, and even with robust earnings sharing setting rates without reference back to underlying costs results in unacceptable volatility in customer bills from year to year by setting rates which significantly diverge from costs only to true up customers later. Large gas consumers (perhaps all gas consumers) budget based on rate expectations. Significant out of period adjustments resulting from an over-reliance on earnings sharing are problematic.

APPROPRIATE REBASING DEFERRAL PERIOD

30. As noted at the outset of this submission, IGUA does believe that barriers to shareholder investments reasonably required to realize efficiencies should be removed, and further endorses provision of reasonable incentives to encourage utility shareholders to make such investments.

31. IGUA also recognizes that requiring rebasing before the Applicants better understand the potential synergy cost and benefits expected to result from the merger might result in a cost of service filing that does not reasonably reflect optimally informed cost forecasts. In this result, the problem of rates diverging from actual costs would not be properly resolved.

32. While 10 years to achieve greater clarity on post-merger costs to serve might be too long, 1 year may be too short.

33. Further, given that it would likely take a year (2019) to prepare a cost of service filing, and the better part of a second year (2020) to properly review and rule on such a filing, requiring rates to be reset based on a cost of service without any rebasing deferral (practically, for 2021) might not provide sufficient time for the Applicants to properly determine an Amalco cost structure on which to base proper cost reflective rates.

34. What is a sufficient period of time to achieve clarity on cost rationalization, allow for recovery of reasonable transition costs, and provide a reasonable incentive for investment in further efficiencies is a matter of judgement. SEC and other parties have undertaken extensive financial and forecast analysis, and we will not replicate this work. While IGUA does not espouse a particular adjustment period, IGUA urges the Board to consider the various submissions received and exercise its judgement on an appropriate rebasing deferral, which lies somewhere between 2021 (the earliest practical rebasing date) and 2029 (as proposed).

35. Key to a proper determination of a current and expected Amalco cost structure will be a fully developed integrated distribution system plan. To inform the Board's deliberations, in reply the Applicants should clearly indicate the earliest date by which they reasonably expect to be able to file such a plan.

ROBUST EARNINGS SHARING PENDING REBASING

36. Pending rebasing, a more robust earnings sharing mechanism is necessary in order to ensure that:

(a) the benefit of synergies, both those historically realized and those about to be realized, is appropriately shared between shareholders and customers; and

(b) (in accord with the basic principles of IRM) the shareholder is provided with a reasonable incentive to find efficiencies but precluded from realizing a windfall at the expense of customers.

37. The Applicants have proposed a rate plan in which they would share earnings only commencing in 2024, and then only earnings in excess of what, by today's standards, would be a 12% utility ROE (i.e. OEB approved ROE of 9% plus 300 basis points), and then doing so only on a 50/50 basis such that shareholder earnings would continue to rise. This is <u>not</u> an appropriate sharing of benefits for a merger of this scale and scope (where sensitivities indicate swings in the billions of dollars). It is even more inappropriate after coming off 5 year rate plans designed and justified on the basis that sustainable efficiencies would be shared with ratepayers commencing in 2019.

38. To properly balance interests and protect ratepayers, IGUA endorses an earning sharing mechanism which:

(a) calculates earnings subject to sharing based on actual costs to serve in the subject test year (as is currently the practice);

(b) applies immediately, as of 2019, and for the duration of any rebasing deferral;

(c) shares earnings above OEB approved ROE;

(i) 50/50 between 0 and 200 basis points;

(ii) 80/20 in favour of ratepayers between 201 and 300 basis points; and

(iii) 90/10 in favour of ratepayers for any earnings in excess of 300 basis points.

39. The foregoing would be optimal from a ratepayer perspective, given the significant current unknowns regarding merger costs and benefits (both quantum and timing). IGUA

acknowledges, however, that there are many ways to adjust these recommended parameters to provide greater or lesser incentive at different post-merger points. For example, should the OEB be persuaded that greater cost recovery opportunity or investment incentive is warranted in the early years post-merger;

(a) sharing of first level earnings could be more heavily weighted in favour of Amalco (if this course is pursued, IGUA advocates 75/25 sharing in favour of the shareholder between 0 and 100 basis points); or

(b) a dead band could be added in the early years (if this course is pursued, IGUA advocates a 100 basis point dead band in 2019 and 2020); or

(c) earnings sharing could be deferred altogether for some number of years (if this course is pursued, IGUA advocates deferring earnings sharing for 2 years[11]).

40. Any such modifying considerations, however, should be tempered by the facts that:

(a) Both EGD and Union have consistently over earned during their respective 5 year incentive rate plans currently ending, even with efficiency expectations embedded in those rate plans.

(b) The Applicants have repeatedly noted that their planning is yet in its early days, with details to be worked out and a range of expected costs and benefits reflecting significant current uncertainty.[12] This militates in favour of protecting rate payers against an unintended shareholder windfall.

OTHER RATE PLAN ADJUSTMENTS

Sharing 2014-2019 Efficiencies

41. An essential aspect of IRM is that sustainable efficiencies thereby incented accrue to the benefit of the shareholder during the plan term, and are “returned” to ratepayers at the end of the plan term as part of the transition to the next plan term.

[11] See Confidential Exhibit JT1.2, page 10, Exhibit 5 table re milestones and Confidential Transcript Volume 1 (Thursday May 3, 2018), pages 108 to 110.
[12] Transcript Volume 1 (Thursday May 3, 2018), page 97 and page 99 through 104, line 5.

42. That both Union and EGD have benefited under their current IRM plans is evidenced by the fact that they have, throughout the 5 year terms of their respective plans, earned in excess of the Board approved ROE (i.e. "over earned").

43. As noted earlier in these submissions, both Union and EGD would, but for the proposed merger, rebase rates for 2019.

(a) Union committed in the settlement agreement in support of is current incentive rate making (IRM) plan to file a cost of service application (whether or not it requested rate setting on that basis) for 2019, and the Board ultimately accepted that settlement agreement in support of approval of Union's current IRM plan.

(b) EGD made a similar commitment during the hearing for approval of its current Custom Incentive Rate IRM plan, which commitment was also accepted by the Board in approving EGD's current plan.

44. While in the current circumstances, the Board has no choice but to set 2019 rates on a basis other than through a comprehensive cost of service process, IGUA agrees with other parties that, at a minimum, the Board should require that "base" 2019 rates be adjusted downward by the weather normalized over-collections (relative to a Board approved ROE) by each of EGD and Union in 2018.

Z-Factor Materiality Threshold

45. IGUA also agrees with other parties that a $1 million materiality threshold for z-factor qualification is absurdly low for what will be the largest regulated gas utility in Canada and the 2nd or 3rd largest in North America. At a minimum Amalco's Z-factor materiality threshold should be set at $10 million (as is that of Ontario Power Generation, Ontario's next largest regulated energy sector participant).

ICM Depreciation Threshold

46. In respect of ICM criteria to be applied during any deferred rebasing period, Amalco should be required to establish ICM eligibility based on actual 2018 depreciation expense (and

not, in Union's case, 2013 depreciation expense). Further, any ICM calculation should be based on the combined depreciation levels of EGD and Union in 2018.

Panhandle System Cost Allocation Inequity

47. Finally, IGUA has a particular concern regarding the current inequity in allocation of the costs of the recently executed Panhandle reinforcement, approved by the Board in early 2017.

48. In EB-2016-0186 Union Gas sought, and obtained, leave to construct a $264 million Panhandle system expansion. That expansion increased Union's Dawn to Dover capacity in order to alleviate supply constraints and allow for growth in demand in the Leamington-Kingsville service area, primarily from greenhouse operations but also from commercial and small industrial customers and anticipated residential growth.[13]

49. In its Panhandle expansion application, in respect of the expansion costs Union proposed a departure from its previously (in 2013) approved methodology for allocating Panhandle system costs.[14] In respect of the expansion costs, Union proposed allocation in accord with design day demands on the system being reinforced - the Panhandle system – updated to include the incremental design day demands to be served by the enforcement project.

50. Under Union's approved 2013 cost allocation methodology Union's Panhandle system costs and St. Clair system costs were aggregated and then allocated to rate classes based on design day demands of the respective rate classes on both systems in aggregate. This cost allocation methodology simplified allocation of costs to ex-franchise customers shipping on one or both of the two systems, and worked for in-franchise customers when the costs of the two systems were relatively equivalent, as was the case in 2013.

51. Union's proposal for a different (interim) allocation of Panhandle expansion costs was advanced because with the addition of the significant costs of the expansion which related

[13] EB-2016-0186, Decision and Order, page 1.
[14] EB-2016-0186, Exhibit A, Tab 8, page 6.

only to the Panhandle system, the use of the combined system for cost allocation purposes no longer reflects the costs to serve customers on each respective system. The 2018 revenue requirement impact of the Panhandle expansion project costs of approximately $27.2 million represents a significant increase (more than 300%) over the 2013 Board-approved total combined (Panhandle and St. Clair Sub-system) revenue requirement of $7.1 million.[15] Yet the benefits associated with this investment accrue only to customers served by the Panhandle system, and provide no benefit to customers served by the St. Clair system.

52. Union's evidence in the Panhandle expansion application was that[16]:

(a) Union's large industrial (T2) customers represent 23% of the design day demand on the Panhandle system, but under the status quo (2013) allocation methodology bear 42% of the Panhandle expansion project costs.

(b) Conversely, the balance of Union south in-franchise customer classes represent 77% of the design day demand on the Panhandle system but under the status quo allocation methodology bear only 43% of the expansion project costs.

(c) In particular, Union's M1 customers represent 40% of the design day demand on the Panhandle system but bear only 21% of the expansion costs.

53. In its February 23, 2017 Decision and Order on the Panhandle expansion, the Board declined to implement the proposed departure from previously approved Panhandle sub-system cost allocation for the expansion project costs. The Board noted that, while the proposal may have merit, a comprehensive review is required for the Board to assess the merits and implications of the proposal, including the impacts on all affected customer classes, and this should be at Union's next cost of service or Custom IR application.[17] At the time of that decision, it was anticipated that Union would make a full cost of service filing for the 2019 rate year, as it had previously committed to do.

54. By the time of Union's application to set rates for 2018 [EB-2017-0087] these merger and rate plan applications had been filed at it was apparent that the Applicants were proposing

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[15] EB-2016-0186, Exhibit A, Tab 8, page 7.
[16] EB-2016-0186, Exhibit J1.2, Attachment 2, page 3.
[17] EB-2016-0186, Decision and Order, page 11.

to defer a cost of service review for at least a decade, and had no plans to undertake a cost allocation study in the interim.[18]

55. IGUA raised the Panhandle expansion cost inequity issue in Union's 2018 rate case, and sought to file evidence in that case to demonstrate the impact on 4 of its Sarnia area members of the cost allocation inequity. The Hearing Panel in that case declined to accept IGUA's evidence, ruling that *"cost allocation issues can be better addressed prior to Union entering another price cap rate mechanism framework"* and that *"any cost allocation changes are appropriate to be considered for setting of 2019 rates"*.[19]

56. IGUA was, however, permitted to advance argument regarding alternative remedies based on the record already compiled for the Union 2018 rate proceeding, and did so. While the Board declined to grant IGUA's proposed relief in that case (declaring Union's 2018 rates interim pending resolution of the Panhandle expansion cost allocation issue), it reiterated its expectation that:

> *The issue of the allocation of these costs on a going-forward basis to Union rate classes will be dealt with in union's 2019 rates proceeding.*[20]

57. The Union 2018 rate case Hearing Panel further expressed the view that; *any change to the existing cost allocation model should be done with the assistance of a comprehensive system-wide full cost allocation study"*.

58. Union has confirmed in the current proceeding that it still intends to address the Panhandle cost allocation inequity as part of its 2019 rate application. Mr. Kitchen testified to Union's view that it will be able to propose adjustment to the allocation of Panhandle costs for 2019 absent a full cost allocation study because the costs in issue are *"isolated to one functional classification"*.[21]

59. Mr. Kitchen had earlier responded to a question from Member Spoel and indicated that, subject to a number of necessary assumptions (given the lack of a combined cost

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[18] EB-2017-0087, Exhibit B.IGUA.4, page 2.
[19] EB-2017-0087, Procedural Order No. 3, page 2.
[20] EB-2017-0087, Decision and Rate Order, page 8.
[21] Transcript Volume 5 (Friday May 18, 2018), page 58, lines 14 to 16.

allocation study at this time), it would be possible for Union to run a cost allocation study during the proposed rebasing deferral period.[22]

60. It is unacceptable to IGUA that another decade pass prior to rectification of this obvious cost allocation problem.

61. While IGUA is focussed on a cost allocation anomaly in respect of the recent Panhandle expansion, we anticipate that one or more other parties will have analogous concerns with other aspects of the 2013 vintage "status quo" cost allocation underpinning current rates.

62. Regardless of the determination in this case of when Amalco will be required to file a cost of service application, IGUA urges the Hearing Panel to clearly direct that Amalco file sufficient cost allocation information in its 2019 rate application to finally address a more equitable allocation of Panhandle expansion costs.

63. To assist the Hearing Panel, IGUA asks that in reply, the Applicants definitively address how they propose to effect an update to cost allocation for Panhandle expansion costs, and any other cost allocation anomalies raised by other parties in their arguments, for 2019 rates.

64. If the Hearing Panel is not satisfied with Union's reply in this respect, then IGUA urges this Hearing Panel to direct Amalco to file a full cost allocation study to support review and reallocation of Panhandle system costs (and any other cost allocation concerns reasonably demonstrated by other parties) as part of its application to establish 2019 rates, regardless of the decision on whether or not a rebasing deferral will be granted.

Harmonization of Services

65. Finally, IGUA notes that the Applicants have indicated that new services or service adjustments may be advanced during a deferred rebasing term. This is an important specification from IGUA's perspective. IGUA expects the combining utilities to review and expand best practices and customer services to their entire combined customer base to

[22] Transcript Volume 5 (Friday May 18, 2018), page 48, line 23 to page 49, line 7.

the extent they are reasonably able to do so. For example, Union's customer managed service (CMS) has been tremendously valuable to at least one IGUA member, and is a service supported by its robust Unionline customer interface system. EGD does not currently offer an analogous service, and its Entrac system is more limited in this respect. When Amalco is making choices about which systems to adopt and which to discard, it must be cognizant of customer service and value issues in addition to economics. IGUA assumes that it will be at liberty to explore these sorts of issues during regular stakeholder engagement meetings and, as required, in annual rate adjustment proceedings, and would ask the Applicants to so confirm in their reply submissions.

ALL OF WHICH IS RESPECTFULLY SUBMITTED by:

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June 15, 2018

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