EB-2017-0306/07

ONTARIO ENERGY BOARD

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

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

UNIFOR
EB-2017-0306/07
COMPENDIUM PANEL 1

DOCUMENTS

1. Response to Unifor Interrogatory - Exhibit C.Unifor.1
2. Response to BOMA Interrogatory - Exhibit C.BOMA.16
3. Response to VECC Interrogatory - Exhibit C.VECC.9
4. Transcript Enbridge Union - Technical Conference – March 28
5. Union Study Labor and Materials Calculations - Interrogatory Response from Applicant
6. Enbridge Study Labor and Materials Calculation - Interrogatory Response from Applicant
7. Decision with Reasons on Motion - February 10, 2003

TAB 1

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Unifor

MAADs Issues List – Issue No. 1

Reference: Section 4.6: Estimated Cost Efficiency Opportunities (Exhibit B, Tab 1, p. 25 of 44)

Question:

a) What workforce restructuring and alignment are the applicants contemplating in the area of Customer Care?
b) What workforce restructuring and alignment are the applicants contemplating in the area of Distribution Work Management?
c) What workforce restructuring and alignment are the applicants contemplating in the area of Utility Shared Services?
d) What workforce restructuring and alignment are the applicants contemplating in the area of Storage and Transmission, Gas Supply and Gas Control?
e) What workforce restructuring and alignment are the applicants contemplating in the area of Management Functions?
f) What workforce restructuring and alignment are the applicants contemplating in the area of Other Functions?
g) What system and process integration are the applicants contemplating in the area of Customer Care?
h) What system and process integration are the applicants contemplating in the area of Distribution Work Management?
i) What system and process integration are the applicants contemplating in the area of Utility Shared Services?
j) What system and process integration are the applicants contemplating in the area of Storage and Transmission, Gas Supply and Gas Control?
k) What system and process integration are the applicants contemplating in the area of Management Functions?
l) What system and process integration are the applicants contemplating in the area of Other Functions?

Response:

Please see response to BOMA Interrogatory #16 found at Exhibit C.BOMA. 16.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Unifor

MAADs Issues List – Issue No. 1

Reference: Table 4 (Exhibit B, Tab 1, p. 26 of 44)

Question:

a) How did the applicants arrive at potential O&M savings of between $350 million and $750 million?
b) How did the applicants arrive at potential capital investment costs of between $50 million to $250 million?

Response:

Please see response to BOMA Interrogatory #16 found at Exhibit C.BOMA.16.

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Unifor

MAADs Issues List – Issue No. 1

Reference: Distribution Work Management (Exhibit B, Tab 1, p. 31 and 32 of 44)

Question:

a) How did the applicants arrive at a related savings estimated at $11 million per year?
b) How do the applicants' estimated savings increase to $16 million per year in 2024-2028? The explanation given, namely 'optimizing third party contracts and consolidating the workload planning and dispatching functions' is unclear in its meaning and potential implications.

Response:

Please see response BOMA Interrogatory #16 found at Exhibit C.BOMA.16.

TAB 2

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Building Owners and Managers Association ("BOMA")

MAADs Issues List – Issue No. 2

Reference: *Ibid, p29*

Question:
The evidence states that the combined customer care annual expenditure is $150 million.

(a) Please break that amount down by company, and by category of expenditure, so as to give a clear picture of customer care activities and their costs. Please include both OM&A and capital.

(b) Please define the scope of what are considered customer care expenditures in each company. Please identify any material differences.

(c) What is the customer care cost per customer for each of Union and EGD in 2016 and 2017, and (forecast) for 2018?

(d) The company states it intends to deliver customer care savings of $15 million (10% reduction to combined customer care expenditures in 2020-2023:
   (i) Please explain how the reduction ($4 customer care per customer will be achieved).
   (ii) Please confirm that the steps taken to achieve the level of savings in 2020, 2021, 2022 and 2023, including increasing the percentage of e-bill customers, increasing collection efficiencies and "work force adjustment", do not require material capital expenditures. Please explain each of the initiatives in detail, showing what savings are forecast per each year from each activity, eg. from increasing the percentage of e-bill customers by a forecast amount and savings per additional e-bill.
   (iii) Please confirm what level of capital expenditure in 2019, 2020, 2021 is required to achieve the $4 per customer reduction in 2020. In what year will Amalco realize its 10% target? Will any capex be required to reach this target? How much?
   (iv) Please advise the status of the planning for these changes since February 2017 (the EGD/Spectra acquisition closing date).
   (v) Please explain the increase in annual savings from $15 million to $26 million in 2024.
   (vi) Please account for the manner in which EGD customer care expenditures have been handled pursuant to the CIS Settlement Agreement over the last several years in setting the customer care baseline. The intent here is to set a "customer care baseline", and to explain the $150 million stated in evidence.

(vii) Please provide a detailed schedule for the integration of the customer care software program. Why is it necessary to integrate customer care operations to a single software system? What are the costs, benefits, risks in making this integration?
(viii) Please provide a detailed explanation of the proposed $65 million cost of implementing the software integration.
(ix) Please deal with the apparent inconsistency between the numbers in Attachment 12 and the range for the same task included in Table 4, which provides a range from $25 million to $110 million.
(x) The evidence is that the project time will take two to three years. What is the schedule for the implementation of the project capex planned for each year, and describe the components of the project plan to be accomplished in each year? Please provide a copy of the implementation plan.

Response

(a) The customer care annual expenditure of $150 million used in establishing the high level cost savings estimate represents an approximation of EGD's and Union's customer care annual costs. The estimate was not built up by cost category.

(b) Customer care expenditures include billing, call answering, collections, postage, and meter reading. At a very high level, a key difference between the two utilities' customer care services is that EGD outsources some of its customer care functions while maintaining ownership of the underlying customer care systems. Union in-sources most of its customer care services while leasing its underlying customer care system. As a result of this difference the Union customer care expenditures also include costs associated with web-based applications and billing systems while the EGD costs do not.

(c) Please see the response to VECC Interrogatory #9 found at Exhibit C.VECC.9.

(d) (i), (ii) (iii) (v) (vii) (viii) As described above, the company has not conducted any detailed integration planning. Attachment 1 provides the narrative of the high level cost estimates and savings planning undertaken for Management review/approval. Appendix B and C were created to respond to the many interrogatories relating to how the estimates were generated.

(d) (iv) (x) The company has not commenced any detailed planning on the integration of utility functions. The company will commence the detailed integration planning upon Management receiving approval of the amalgamation by the OEB, the EGD, Union and Enbridge Inc. Board of Directors.

(d) (vi) Please see response (a) above to understand the $150 million customer care amount used in high level integration planning. This estimate includes EGD's customer care expenditures.

(d) (ix) Attachment 12 provides the yearly profile and ten year totals of the estimated capital investment and potential O&M savings for each of five functional areas. Table 4 provides the range of potential capital investments and O&M savings that Management believes may arise depending on the outcome of the detailed integration planning and ultimately final execution of all integration activities. The ranges provided in Table 4 highlight the potential range of cost and savings outcomes as a result of underspending or overspending on capital investments and underachieving and overachieving on O&M savings.

Utility Integration Opportunities: Cost and Savings Assumptions

Utility Integration High Level Planning Process

To identify the potential integration opportunities, Management met jointly and reviewed the existing functional areas within each utility. This included a review of the historical financial operations, the key business process areas and supporting software and business systems. The review allowed Management to compare and contrast historical operational results and future forecasted results including: financial results for the prior 5 years, detailed results for the 2017 forecast and 2018 budget for the utilities Operations for Enbridge, and the long range strategic plan for the Utilities Operations for Enbridge.

Based on this review, the following key functional areas for integration were identified:

1) Customer Care,

2) Distribution Work Management,

3) Shared Services,

4) Storage & Transmission Operations and Gas Supply & Control,

5) Management and Other Functions (Engineering, Integrity, Public Affairs, Demand Side Management, Cap & Trade, Business Development).

Management has extensive expertise and knowledge of the operations of each utility and was able to draw on the results from previous operations reviews and business process improvement projects that have been implemented over the past 15 years for each utility under their respective Custom Incentive Regulation frameworks. The cost estimates included in the Utility Integration Plan are based on the known costs for each utility for both capital and operating expenses and forecasted expenditures. The 10 year Asset Management Plans for each of the utilities is the basis for the capital expenditures over the 10 year MAADs framework timeline.

Summary of O&M Savings and Related Capital Costs:

The following section details the assumptions underpinning the estimated cost efficiency opportunities for the integrated utility ("Amalco") in the five functional areas listed above.

The estimated savings and associated capital investment are summarized in Table 2 below and the annual impacts from 2019 to 2028 are provided in Appendix A. Field Operations have been excluded from the scope of the analysis at this time to ensure consistency of safe and reliable operations and to reflect that service areas for each utility do not directly overlap, though they will be adjacent in some areas.

The estimated capital investment required for integration of technology to support the integration of processes is between $50 million and $250 million to deliver potential net savings in operating costs of between $350 million and $750 million over the deferred rebasing period, depending on the level of integration and timing of investment.

Table 1

High Level Minimum and Maximum Cost and Savings Estimate

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

While the groups and functional areas that will generate synergies have been identified, the detailed implementation plans will only be developed and implemented after a successful conclusion to the regulatory process. Many of the synergy opportunities are tied to the ability to eliminate duplicate systems and processes through the alignment of processes, procedures, standards and specifications. Whenever possible, the final Implementation Business Case will leverage existing processes, procedures and supporting software applications that are already in place to minimize costs and overall change impacts.

Risks

The highest perceived risk to achievement of the O&M synergies is the pace and number of concurrent changes within the organization. A dedicated and focused Project Management Office supported by external expert resources will ensure all work streams are aligned, risks are identified and mitigated. Throughout the implementation period, impacts to field operations will be carefully considered to ensure continued safe operations while the customer care stream will focus on implications and impacts to our 3.5 million customers.

Multiple Large Scale Software Implementations

Significant software system implementations will take place over the ten year deferred rebasing period from 2019 to 2028. Large scale system implementations will be staggered to allow for staff to be resourced to these projects and to support change management and adequate adoption of the new systems and processes by employees and vendors. The timing of these system implementations will also need to consider corporate Enterprise Resource Planning (ERP) system initiatives that will be happening concurrently throughout this period. The estimated cost efficiencies related to systems implementations is based on a moderate to aggressive timeline, as three large system implementations are projected to be completed by 2024.

The first large system implementation that will potentially affect the utility integration is the enterprise ERP migration. The second large system implementation is the Distribution Work Management system unification. The third large system implementation is the migration to one customer care software application. Each of these projects has a two to three year project duration and each large system implementation carries both timeline and cost risks. Management will ensure no-harm to the customer experience through these multiple system changes by balancing quality outcomes with cost and timeline risks. The utilities have recent experience with large software implementations including SAP, ConTrax, Oracle, SCADA and Maximo system implementations and will be supported by the Enbridge enterprise support teams and external expert resources as required.

Business Process Transformations

Integration of the utilities' business processes is generally expected to take place over the first six years. The breadth of this integration and the associated business process transformation is significant. To provide context for the breadth and potential complexity of the integration consider the following examples:

- Alignment of engineering policies including pipeline and facilities construction, inspection, maintenance and distribution operations, etc.
- Common processes for supply chain procurement.
- Alignment of safety policies and practices.
- Common work management processes including estimating, planning, scheduling, and execution practices and policies.

- Consistent accounting practices and policies including consolidated financial forecasting and reporting.
- Alignment of various management systems (asset, emergency response, safety, etc.)
- Alignment of the 10 year asset management plan including risk identification and mitigation practices.

In addition to the operational processes that will be integrated, one of the most significant undertakings will be to integrate the two utilities' customer care operations. A detailed review will identify the differences between the two utilities' methods and approaches and a plan will be developed to manage the transition accordingly. This integration of the customer care operations is forecasted to deliver savings five years after the legal amalgamation in 2019. The unification of the customer care service delivery models can only be accomplished with the implementation of a common customer care approach and related software support.

Given the inter-dependencies and the breadth of integration between systems and business transformation there is a risk to the moderate to aggressive timeline and therefore a ten year deferred rebasing was selected to provide sufficient time for Management to achieve a fully aligned and stabilized integrated utility prior to rebasing in 2029.

Capital Cost Assumptions

Customer Care

Currently the two utilities have different customer information software (CIS) applications and approaches. EGD utilizes SAP software to support its Customer Care activities that had an implementation cost of approximately $118 million and relies on Accenture as an outsource provider for some of the customer care functions. Union contracts with Vertex to use the Banner Customer Care system to support their internally delivered customer care operations. The integrated utility will unify customer care operations under a single CIS and supporting software platform. A detailed analysis will be completed to determine the best customer care solutions to deliver quality services to our customers. The range of solutions includes migration of Union data and business processes into the EGD SAP software, migration of EGD data and business processes to the Union platform, and implementation of a new system. The estimate of $65 million represents migration to one of the current existing software platforms and structures. The estimate is approximately 50% of the original EGD SAP software implementation costs.

Distribution Work Management

EGD completed an implementation of a new software platform (Maximo) to support work management systems in 2016 at an approximate cost of $85 million. The current software supporting the Union platform (Advantex) is nearing end of life and will not be supported in the near future. While a detailed analysis of options is required, the estimated cost efficiencies are based on integrating Union and EGD into a Maximo software system. Management estimates that a potential range of implementation costs could be between $30 million for data and business process migration to $85 million for full implementation. The estimate for migrating Union processes and data into Maximo is approximately $50 million.

Utility Shared Services

There are a number of Shared Services such as Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability that are resident at the utility and provide specific utility based shared services. Initiatives to align shared service functions across the enterprise are ongoing and are part of the overall corporate merger integration and not managed directly by the utilities.

There are smaller systems and software that are specific to the utility functions that reside in shared services. The initial review has identified applications such as: Utility contract management (EGD uses CMS and Union uses Ariba), utility billing financial analysis (EGD uses RAVE), IT service requests (EGD uses Service Now and Union uses an in-house system), real estate services (EGD uses Archibus and Union does not have a dedicated software application). This listing of utility software applications will be refined and then reviewed/rationalized against the overall Enbridge enterprise software pillars of Finance and Human Resources (Oracle and WorkDay) to determine the best package to meet the local utility functional requirements.

An initial preliminary estimate to implement a common software platform for those areas of shared services is set at $13 million. This cost estimate reflects implementation of between 5 to 10 systems resulting with an average implementation cost range of $2.6 million for 5 systems and $1.3 million for 10 systems.

Overall Management estimates that the range of costs for these shared services systems is between $5 million and $20 million.

Storage and Transmission Operations and Gas Supply and Control

Union's Storage and Transmission facilities are larger than that of EGD. Union has its SCADA system in Chatham and EGD has a distinct SCADA system in Edmonton. Union and EGD use different software applications for their Gas Supply settlement processes (UNION usesConTrax and other smaller systems and EGD uses OpenLink, EnCore and Entrac). A high level preliminary estimate to integrate the SCADA system and selection of software for gas supply operations to a common platform ranges from $5 million to $10 million. The midpoint of this cost range is approximately $8 million as an unclassified estimate.

Other Functions

With respect to Asset Management, EGD has progressed with its implementation of its Asset Management processes using the RIVA software. The RIVA software and associated processes provide capital business case entry, evaluation of engineering asset health and asset investment optimization. Management expects some small amount of costs to integrate Union and EGD into the single asset management processes and software given the system is standalone to the distribution work management software system.

Union and EGD have several systems that facilitate day-to-day operation of the utilities. Some of the different systems include: GIS, extranet websites, different meter-reading based software and several data warehouses that facilitate data analytics and reporting. Management plans to start the integration of these utility systems in 2019 and has preliminary initial cost estimates ranging from $5 million to $20 million. An average range of per system capital costs between $0.5 million and $2 million has been used to migrate or replace a range of 7 to 30 systems. (30 systems @ $0.5 million per system = $15 M) The unclassified estimate of $14 M has been used as a baseline capital cost estimate for the Other Functions/systems.

Net O&M Savings Assumptions

Customer Care

Management will start Customer Care integration efforts subsequent to an OEB decision on our MAADs integration application, evaluating the costs and benefits of the various alternatives and identifying the optimal solutions to implement common approaches and supporting software. As detailed above, EGD has outsourced customer care services while using internal software to support these services (SAP for Utilities). Union has insourced customer care services while using an external system to support the billing and related functions (Vertex's Banner software).

The two customer care groups have different operating practices. The principal metrics to evaluate the various options will be to ensure we are maintaining or improving customer service levels while lowering the total cost to provide customer service. Projected savings (prior to any system changes and alignment) have been based on a medium to aggressive schedule expectation with planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2019. The goal is to target the delivery of the first tranche of savings in 2020 to 2023. Savings in this first tranche are targeted to realize a 10% reduction to the combined utilities' customer care services cost (estimated to be approximately $150 million in total. 10% * $150 million = $15 million). This reduction would equate to an estimated reduction of approximately $4 /customer across the combined 3.5 million customer base. These efficiencies could be the result of activities such as a digitization campaign to increase e-bill customers, increase collections efficiencies, optimize the workforce with one of either the Union or EGD model or a hybrid approach where some services are outsourced and others insourced.

A major long term contributor to achieving further efficiencies in the customer care function is the migration to a single CIS platform. Migration is currently targeted to be in-service by 2024. The unification onto a single software platform is expected to accompany the implementation of processes that enhance moving to the single software platform. The combination of moving to a single platform is expected to improve customer service offerings and reduce the workload required to process customer interactions and service. The expected total cost of operations for customer care services in 2024 is projected to be approximately $135 million per year ($150 million net of $15 million annual savings). Given efficiencies achieved in the first phase of the customer care business optimization plan (2020 to 2024), a goal to further optimize by an incremental 7.5% from the earlier 10% cost reduction is seen as aggressive but achievable. The incremental 7.5% can deliver an additional $10 million per year from 2024 to 2028. Overall, the targeted reduction in annual O&M costs by 2024 is approximately 17% below the 2018 forecasted level of $150 million. These reductions are to be achieved from a combination of increased number of e-bill customers through better customer care web services, migration to a single CIS platform and rationalization of processes to implement best practice and processes that accompany the customer care system which should support some reduction in duplicative workforce.

A key consideration for the delivery of customer care efficiency plan outcomes is execution and specifically the dependency on other system transformations that the Enbridge enterprise and the integrated utility will undertake. The Enbridge enterprise is undertaking a finance transformation which will implement a common ERP system at some point between 2019 and 2021. This timing will impact the ultimate timing and delivery of a unified customer care software system given this system is the "cash register" for the integrated utility revenues. In addition, timing of software migrations undertaken at the utility such as the work management system, gas supply and commercial marketer and transmission software systems will impact the delivery of the customer care integration plan. Finally, the scope and size of the software implementation is uncertain at this time given the current options for the final software and customer care approach. Table 2 highlights the cost and savings range uncertainty.

Distribution Work Management

Distribution work management is the planning, scheduling, compliance, work management systems (WMS), WMS support, asset management and support for overall work to maintain our assets and to plan and schedule work across both Union and EGD. There is an opportunity to eliminate redundancy of systems and improve worker efficiencies in the planning and scheduling of field work by adopting the best practices from both utilities and to consider which model will deliver the best outcome in terms of customer service and cost. Savings have been estimated at $11 million/year or 10% of the estimated 2016 costs ($110 million). The estimated savings increase to $16 million/year in 2024 to 2028 is due to optimizing 3rd party contracts.

EGD has recently implemented the Maximo software platform in conjunction with the eGIS software and Click Mobile software as its end-to-end distribution work management system. The Maximo platform is established as a solid base for future optimization of this business function. The primary area of integration focus for this business function is the back-office activities, integration with customer care services to improve offerings/delivery times to customers and software unification. The two companies have different approaches to how the distribution work management function is undertaken. An integration plan will be undertaken to evaluate each distribution work management process and to implement the best practice at the lowest cost. Given that both utilities have optimized workforces and optimized internal processes on a standalone basis and the integrated utility has forecasted approximately 50,000new customer additions per year, an estimate of 10% further reduction in costs and workforce planning is seen as moderate to aggressive.

Utility Shared Services

Utility Shared service functions at Enbridge include: Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability. The Enbridge corporate office functions began to integrate and optimize the combined Spectra and Enbridge shared services at the close of the merger in Q1, 2017. A significant consideration for Management in the corporate shared service integration plan is the distinctness of the utility function relative to other business units in the new Enbridge. The Utility Finance, Human Resources, Information Technology, Supply Chain Management, Real Estate Services and Enterprise Safety & Operational Reliability requirements will be addressed by Management by reviewing practices currently executed between the two utilities to determine the impact of implementing a range of harmonization and standardization within these.

The targeted savings are estimated to be 2% to 7% of the combined annual operating costs which equals approximately $2 million to $7million per year on an approximate base cost of $100 million for the integrated utility.

Storage and Transmission Operations and Gas Supply and Control

The Storage and Transmission Operations and Gas Supply business function include operations and maintenance of the transmission pipeline systems, storage wells and reservoirs. Gas Supply and Gas Control includes the gas control room operations for both EGD and Union, gas supply and upstream transportation contracting and settlement processes and associated systems and software for both utilities. There are some opportunities to apply best practices across the utilities and to determine if there are operational benefits available related to the combination of these assets. The integration and alignment of the SCADA systems will also yield a potential benefit. The primary cost savings is expected to come from harmonizing the SCADA systems to one, process changes to optimize maintenance costs and alignment of contracts. The savings are estimated to be an average of $3 million per year over the ten years or approximately 10% of the annual $30 million in cost.

Management Functions

There are opportunities to rationalize the Management structure and other functions within the integrated utility. Identifying a single Management structure and Executive Management Team is one of the first integration efforts that will be conducted. Broader workforce reductions are expected to occur at a much more gradual pace as various integration initiatives are undertaken over the 10 year deferred rebasing period. Considerations by the new Management team with respect to any workforce reductions will require a review and alignment of operational processes and the related systems, and the staff necessary to execute these processes so that safe, reliable business operations continue and service levels are maintained. The savings from the rationalizing of Management structure is estimated to be $180 million over ten years. While this equates to a 7% reduction in combined utility annual salaries and wages of $285 million (net of capitalization), this estimate for potential savings is considered aggressive as a percentage of the Management level salaries. The estimate for Management structure changes is input as $20 million per year with a first year severance cost of $20 million. The estimated $20 million cost reduction will come from a mix of people leadership levels at both utilities. Management used a 25% reduction to an estimated base of 450 combined leadership positions for the purpose of this analysis.

Other Functions

Other functions include business areas such as Engineering and Integrity, Information Technology, Public Affairs, Demand Side Management, Cap & Trade and other Low Carbon Business Development. These groups have opportunities to integrate and drive productivity associated with elimination of smaller software systems, implementing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities. The annual savings estimate from this area is approximately $14 million per year based on a 14% reduction to an annual combined O&M cost estimate of approximately $100 million. Given the majority of the savings will come from the rationalizing of Information Technology systems costs, the savings are expected to be generated in 2024 through 2028.

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

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

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

Appendix B: High Level Estimated Capital Investment and O&M Savings Assumptions Summary

The following table provides a summary of the assumptions that underpin the estimated capital investment and net O&M savings for each key functional area as well as the assumptions used to establish the high level mininum and maximum cost and savings estimates found in Table 2 above.

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
Customer Service	Used EGD SAP software system implementation cost of $118 million as base to evaluate range of potential costs to integrate Union Gas and EGD customer service software. Range of possibilities include: a. Data migration of Union Gas into existing EGD software with a minor amount of system changes. High level cost estimate of this scenario is contemplated as approximately 20% of base cost of $118 million or $25 million. b. Full Implementation of software and system changes. High level cost estimate contemplated as just below the full cost of the EGD SAP implementation given potential cost efficiencies have been achieved since EGD SAP implementation ($110 million) With the range of potential costs being between $25 million and $110 million, an assumption of $65 million, or a value of just over half of the maximum end of the range was used as the basis for the customer service capital investment.	Used an assumption that the combined total O&M cost of approximately $150 million per year. Used a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2020. First tranche of savings in 2020 to 2023: • Savings in this first tranche are targeted to realize a 10% reduction to the estimated combined utilities customer care services cost of $150 million. (10% x $150 million = $15 million per year). As a reasonableness check of the 10% target of reduction in costs, a comparison was made to the equivalent cost per customer reduction. An annual $15 million reduction would equate to an estimated reduction of approximately $4 per customer across the combined 3.5 million customer base. Second tranche of savings from 2024 sustained through to 2028: • The expected total cost of operations for

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		customer care services in 2024 is projected to be reduced from the assumed $150 million by the $15 million of annual savings in the first tranche of integration. • Savings in the second tranche will require an aggressive plan to achieve significant incremental savings. • A goal was set to achieve an incremental 7.5% cost reduction in addition to the first tranche cost reduction of 10% as the second tranche annual percentage savings assumption. • The reduction in annual O&M costs from 2024 onward, as a result of an annual savings of approximately 17% below the level of $150 million equates to $26 million per year in annual savings. The cumulative savings from the first and second tranche of customer service integration equals a total cost reduction of approximately $192 million or a ten year average of $19 million per year. The minimum cost savings was established as two-thirds of the base ten year average or approximately $12 million per year or $120 million over ten years. The minimum cost savings assumes that the aggressive 10% and sustainable 17% annual savings percentages are not achieved. The maximum cost savings was estimated as an achievement of an incremental one-third cost reduction in addition to the base ten year average. Assuming integration activities exceed the base ten year average

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		cost reduction by one-third, the ten year average cost reduction will result in total maximum savings of $250 million or an average of $25 million per year over ten years.
Distribution Work Management	Used EGD Maximo software system implementation cost of approximately $85 million as base to evaluate range of potential costs to integrate Union Gas and EGD distribution work management software. Range of possibilities include: a. Data migration of Union Gas into existing EGD software with a minor amount of system changes. The cost estimate of this scenario was contemplated as approximately 10% of base cost, or $10 million, based on an assumption that data migration will mean lesser overall project complexity and cost. b. Full Implementation of software and system changes. High level cost estimate contemplated this scenario as being equivalent to the recently completed EGD Maximo implementation ($90 million) With the range of potential costs being between $10 million and $90 million, an assumption of $50 million was established as the base capital investment for the distribution work management integration, or a value of just over half of the maximum end of the range. An assumption that a capital investment scope that would fall between the minimum and maximum project estimated scopes was deemed a reasonable base scenario.	Used an assumption that the combined total cost of distribution work management is approximately $110 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2018 leading into the implementation of several changes starting in 2021. First tranche of savings in 2021 to 2023: • Savings have been estimated at $11 million per year or 10% of the estimated total combined distribution work management O&M costs of $110 million. Second tranche of savings from 2024 sustained through to 2028: • Assumed a second tranche of cost reduction based on optimizing 3rd party contracts, field operations and business process optimization. • Used a goal of achieving 16% cost reduction to the base total combined distribution work management O&M costs of $110 million. The 16% equates to annual cost reduction of approximately $16 million per year.

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		The total savings over ten years from the first tranche and second tranche of estimated distribution work management integration equals approximately $113 million or a ten year average of $11 million per year. The minimum cost savings was established as one-third of the base ten year average or approximately $11 million per year ($30 million over ten years). The minimum cost savings assumes that the aggressive 10% and sustainable 16% annual savings percentages are not achieved. The maximum cost savings was estimated as achieving an incremental one-third cost reduction to the base ten year average. Increasing the $11 million cost reduction by one-third equates to an estimated total maximum savings of $150 million or an average of $15 million per year over ten years.
Utility Shared Services	This estimate is intended to approximate a reasonable cost for integration of several smaller utility shared service groups systems. A number of 15 smaller system integration projects were used as the basis of the estimate. Used approximations of smaller software/ system implementation cost ranges as a base to estimate the range of potential costs to integrate Union Gas and EGD utility shared service groups. Assumed that 5 systems would be implemented at an average of $2.6 million per system and 10 systems would be implemented at $1.3 million. The total cost from this assumption was then halved for purposes of this high level estimate (5 x $2.6 million + 10 x $1.3 million = $26 million/2 = $13 million).	Used an assumption that the combined total cost of utility shared service departmental costs is approximately $100 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that work starts in the later part of 2018 leading into the implementation of several changes starting in 2020. First tranche of savings in 2021 to 2023: • The first tranche is to conduct systems integration projects to implement technology and process efficiencies. • Savings have been estimated at $2 to $3 million per year or 2% to 3% of the estimated total O&M costs of $100 million. • Assumption of annual percentage savings being

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	To determine a range of low and high cost estimates, the $13 million was used as the basis of the utility shared services capital investment. This $13 million was decreased by one-third of its value to estimate the minimum capital investment and the base was increased by one-third of its value and rounded up to estimate the maximum capital investment.	2% and 3% respectively recognizes that the utilities have implemented efficiencies to their local utility shared service groups and therefore, have opportunities stemming from smaller systems and process improvements. Second tranche of savings from 2024 sustained through to 2028: • The second tranche of integration activities are expected to coincide with the stabilization of capital investments in the utility shared services systems and set out a target to achieve incremental savings of 2% to 3% in addition to those estimated in the first tranche of integration. • The second tranche assumption is a target achieving a 5% reduction in the total cost of utility shared services. The incremental 2% to 3% of cost reduction is assumed as a stretch goal and believed achievable through the pursuit of further process and contract efficiencies.
Storage & Transmission	Used an approximation of $5 million to $10 million range as cost estimate to represent contemplation of costs to migrate to one SCADA system and integrate two software systems. Upper cost estimate of $10 million assumed $8 million to integrate SCADA and two software integrations of $1 million each. To determine the minimum capital investment, an assumption of half of the maximum capital investment estimate was used. With the range of potential costs being between $5	Used an assumption that the combined total cost of storage and transmission O&M is approximately $30 million per year. Used an assumption of a medium to aggressive integration project schedule with the expectation that work starts in the later part of 2018 leading into the implementation of several changes starting in 2020. Assumed cost savings are expected to come from harmonizing the SCADA systems to one, process changes to optimize maintenance costs and alignment of contracts.

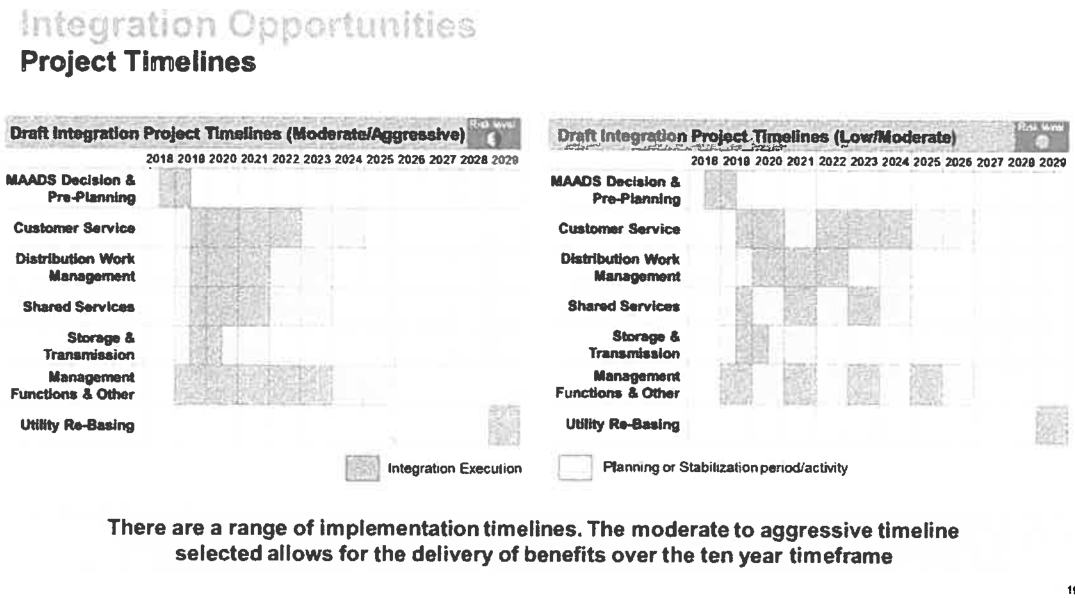
Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	million and $10 million, an assumption of $8 million, the rounded up amount of the midpoint between $5 million and $10 million was used as the basis for the storage and transmission capital investment.	Used an estimate of an annualized 10% cost reduction to the estimated total O&M of $30 million per year to establish an estimate of average annual cost savings. Assumed a stretch target of achieving the average annual cost savings estimate of $3 million per year, over the ten year deferred rebasing period or the equivalent of $30 million of savings. The expectation is that savings will likely commence in 2020 post completion of the capital investment for storage and transmission. Based on the assumption and target to achieve $30 million of savings over the ten year deferred rebasing term, the estimated savings were profiled in a graduated manner over the years of 2020 to 2028.
Management Functions & Other	There are no planned capital investments with the Management Functions functional area. This integration opportunity represents the establishment of the integrated utilities management structure. The Other Functions functional area represents a high level cost estimate to integrate the many smaller scoped software systems that are used by both utilities. A cost assumption range of between $0.5 million cost per system integration to $2 million cost per system integration was considered to be a reasonable approximation of the potential costs to integrate the systems used in these functional areas. Assumed 30 system integration projects with an average cost of $0.5 million per project to establish a base of $15 million capital investment.	Management Functions: Assumed an average per management function salary and wages, short term and long term incentive plan cost reduction of *$175 Thousand.* Estimated a reduction of 25% of the Management base of 450 combined leadership positions resulting in an annual cost reduction estimate of approximately $20 million per year. Assumed severance costs equivalent to the estimated savings of $20 million being incurred in the first year when the management structure change is implemented. The estimated savings from the rationalizing of Management structure is estimated to be $180 million

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
	To determine a range of minimum cost estimates, the base of $15 million was decreased to one-third of its value or $5 million. The maximum cost estimate was established by increasing the base of $15 million by one-third to $20 million.	over ten years. The estimated $20 million annual savings equates to a 7% reduction in combined utility annual salaries and wages of approximately $285 million (net of capitalization), this estimate for potential savings is considered aggressive as a percentage of the Management level salaries. <u>Other Functions:</u> Used an assumption that the combined total cost of Other Functions O&M is approximately $100 million per year. Assumed Other Functions capital investment and potential O&M savings will be a second tranche integration set of activities. Pursuit of efficiencies in these areas will begin after primary (larger opportunity) areas have stabilized. Used an assumption of a medium to aggressive integration project schedule with the expectation that planning work starting in the later part of 2020 leading into the implementation of several changes and savings starting in 2024. Assumed an aggressive estimate of 14% cost reduction per year which is to be achieved by the elimination of smaller software systems, implementing sourcing models to reduce internal system support costs, implementing efficiencies through vendor contract management and process optimization cost savings opportunities. The annual savings estimate from this area is approximately $14 million per year on an annual

Item	Capital Investment Assumption Summary	Net O&M Savings Assumptions Summary
		combined O&M cost estimate of approximately $100 million. Given the majority of the savings will come from the rationalizing of Information Technology systems costs, the savings are expected to be generated in 2024 through 2028.

Appendix C: High Level Integration Project Timelines Assumption Summary

Management provides the following narrative and graph as further context to the high level integration cost and savings estimates. Graph 1 below shows two project Gantt charts that represent potential project timelines setting out the utility integration planning, integration execution and post in-service stabilization periods.



Graph 1 – Draft Integration Project Timeline Illustrations

The graph on the left, labeled Draft Integration Project Timelines (Moderate/Aggressive) shows one potential project schedule that has integration activities being conducted in parallel over the first five years of the deferred rebasing period. Planning for these activities would take place in the early half of 2019 followed by execution of capital investment projects with estimated in-service dates in 2021, 2022 or 2023. After these projects have been put in-service, there are stabilization periods of one to two years for each of the functional areas streams. The stabilization periods will allow for the project warranty periods to be completed and any residual issues to be remediated prior to resuming regular operations. This draft project timeline is the aggressive end of the project timeline spectrum, where the utility undertakes an aggressive and potentially higher risk exercise to complete all estimated integration activities as early as possible.

The graph on the right, labeled Draft Integration Project Timelines (Low/Moderate) shows a second potential project schedule that has integration activities being conducted in a staggered schedule over the first seven years of the deferred rebasing period. Planning for these activities would take place prior to the commencement of the initiative and different from the graph on the left, a period for stabilization and planning prior to commencing the next initiative would be introduced after the initiative was put in-service. The customer service functional area line in the graph on the right depicts the planning and commencement of a first phase of integration activities in 2019 and 2020 after which there is a year of stabilization and planning for the second phase of customer integration which would be conducted over the years 2022 to 2024. In this low to moderate draft project timeline the first phase of the customer service integration would be the integration to one customer service system and the second phase could be a project to implement a single customer service operations. No analysis or scenario planning was performed with respect to the low to moderate project timeline given the high level nature of this planning.

The graph on the right, the low to moderate project implementation schedule has the integration project schedule completing the capital investments in the eighth year of the deferred rebasing term or January of 2027.

The moderate to aggressive graph (Graph 1 left graph) when compared to the low to moderate graph (Graph 1 right graph) provides an understanding of one time duration difference that is required to complete the utility integration, stabilize and return to regular operations. The time range extends from six years under the accelerated project timeline to eight plus years under the more staggered execution project timeline. These are two potential project timelines and given the number and size of integration initiatives being undertaken over the ten year period, Management sees the ten year deferral of rebasing as a key incentive to achieve the full potential of integration activities in a balanced manner that delivers quality within a reasonably paced timeline.

TAB 3

ENBRIDGE GAS DISTRIBUTION INC. AND UNION GAS LIMITED

Answer to Interrogatory from
Vulnerable Energy Consumers Coalition ("VECC")

MAADs Issues List – Issue No. 1

Reference: 306/B/T1/pp. 27-32

Question:

a) How was the year 2024 determined as the year a single customer care (billing system) would be in service?
b) Please provide a table which shows the customer care capital and (separately) operating costs of Union and (separately) EGD for the period 2014 through 2018.
c) Please provide the combined estimated customer care costs of Amalco for the following 10 year deferral period.
d) Please provide the definition (components) of "customer care" costs that are being referred to in response to b and c.

Response:

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

b)

Union Customer Care Cost Breakdown						
Category	**Cost Type**	**Actuals**				**Budget**
		2014	**2015**	**2016**	**2017**	**2018**
Capital ($)	Project Costs	915,084	1,485,625	601,059	214,858	-
	Project Depn	(368,936)	(656,418)	(903,598)	(890,386)	(689,771)
	Reg O/H Costs	317,298	442,942	158,814	53,286	-
	Reg O/H Depn	(42,207)	(80,219)	(110,306)	(120,911)	(123,576)
O&M ($)	O&M Costs	46,489,254	47,082,254	46,771,369	47,074,560	49,297,308
Customer Count		1,419,499	1,436,924	1,458,720	1,474,944	1,497,122
O&M per Customer		32.75	32.77	32.06	31.92	32.93

EGD Customer Care Cost Breakdown					
	Actuals				**IR Budget**
Cost Type	**2014**	**2015**	**2016**	**2017**	**2018**
Capital Costs ($M)	6.1	8.5	7.4	5.6	10.9
O&M Costs ($M)	79.6	83.7	86.4	85.4	110.8
Customer Count	2,063,837	2,094,681	2,124,683	2,156,668	2,180,000
O&M per Customer	38.57	39.96	40.66	39.60	50.83

Notes:

EGD O&M Costs above include the impacts of CIS rate smoothing

c) The company has not conducted detailed planning of integration and does not have a breakout of customer care costs over the ten year deferral period.

d) See part c).

TAB 4

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2017-0306** **EB-2017-0307**	**Enbridge Gas Distribution Inc.** **Union Gas Limited**

VOLUME: **Technical Conference**

DATE: **March 28, 2018**

UNDERTAKING NO. JT1.20: TO PROVIDE THE AGENDA FOR THE MEETING HELD NOVEMBER 22ND AND 23RD.

MR. LADANYI: Could I take you now back to BOMA 16, 16, attachment 1, page 10?

That's a table we've seen several times during this proceeding, page 10 of 20. It is just a very good reference table.

Could you tell me roughly when this table first showed up? Was this table prepared sometime during the summer by somebody? Because we still haven't found out who prepared it, but who would have prepared a table like this?

MR. KITCHEN: Mr. Ladanyi, the table you are referring to also appears in our evidence at attachment 12, and it is the forecast of integration investments and savings would have underpinned the board of directors presentation.

MR. LADANYI: So it was prepared prior to the board of directors presentation which was on November 2nd?

MR. KITCHEN: Yes.

MR. LADANYI: Okay. So when I look at these numbers, they obviously seem kind of high-level. You'd agree with me they are high-level numbers? In fact you say that in the evidence, don't you, in several places.

MR. KITCHEN: It is a high-level estimate, yes.

MR. LADANYI: Okay, so I just -- you know, it is very interesting how high-level they are.

When I look at different columns, for example, and the lines, I look at the lines line called "Additional unidentified efficiencies" and the reason they are not identified is because you couldn't identify them, I guess. But who asked you to put up with more efficiencies? Was it somebody at the Calgary office or head office at Enbridge Inc. saying we do not have enough savings, give us some more numbers. And you couldn't come up with any numbers, so you created a new line -- or somebody either at Enbridge or Union created a new line that said, well, we can't find this stuff, but we'll find it somehow. Is that how it is?

[Witness panel confers]

MR. KITCHEN: There is an IR response that we're just trying to turn up.

There is an IR response, Mr. Ladanyi, that deals with this. But essentially, the unidentified savings required by management to get it back to allowed.

MR. LADANYI: Let me ask you in a slightly different way. Was there a small group working on putting together these numbers in secret? Since most of the senior leaders must not have been involved, they had to be informed about later about it, so they weren't part of this group. There was a select group that came up with these numbers without consulting the senior leaders. Obviously, if they knew all about it, they wouldn't need to be informed, and on that basis...

MR. CASS: If I could stop there, I've been trying not to interfere, because I am hoping it will move along more quickly that way.

But this is a technical conference, as you know, Tom, questions of clarification, not cross-examination. If you want to ask how was a document prepared, fine. But all this innuendo and this commentary, these are not technical conference clarification questions to me.

MR. LADANYI: Sure, well, we'll move on. There are other questions.

CONTINUED FOLLOW-UP QUESTIONS BY MR. QUINN:

MR. QUINN: Before you move on, Tom, I just wanted to loop back. The senior leaders day, I heard Mr. Kitchen undertake to provide an agenda and the presentation that he and Mr. Mandyam did.

Could I also ask in the review of that agenda if there are any other pertinent documents that do reflect on the matters in this case, that those are provided also?

MR. KITCHEN: We will provide the agenda and if there's anything that reflects on MAAD and setting the rate mechanism, we can provide that.

MR. QUINN: Going back to the other one, Mr. Culbert, Mr. Ladanyi was asking about 2014 and '15 productivity results. That's what you filed is '14 and '15.

Your '16 productivity results that were part of EB-2007-0102 and were not produced by Mr. McPherson, but Melinda Yan and somebody else, and that document is different and it is absent from what was provided in response to the IR. So there is a missing 2016 productivity report from this record.

MR. CULBERT: I don't believe so. The two reports in there are 2015 and 2016?

MR. QUINN: You might want to do that subject to check, or take an undertaking to check it because I'm looking at the '16 results produced by somebody else for the stakeholder day. I haven't compared one slide presentation to the other, but in flipping through Mr. McPherson's, that looks like 2014. This is 2016, the one I'm looking at.

MR. CULBERT: I will check.

MR. QUINN: Okay, if we could undertake that.

MR. LADANYI: Before we leave, unfortunately --

MR. MILLAR: JT1.21.

UNDERTAKING NO. JT1.21: TO PROVIDE ANY DOCUMENTS THAT MIGHT SEEM RELEVANT TO THIS CASE FOLLOWING THE REVIEW OF THE AGENDA PROVIDED AS JT1.20

MR. LADANYI: Before we leave attachment 1 of BOMA 16, could you just simply tell me who produced it and when. That has to be really straightforward. There is no argument here. There's got to be a straightforward answer to that question.

The origin of the number, when they were put together and by whom.

MR. KITCHEN: It was produced by management. That's the answer you are going to get, Tom.

MR. LADANYI: Management is hundreds of people and I just don't think it's hundreds. But anyway, we can fill it up in a case.

FOLLOW-UP QUESTIONS BY MR. BRETT:

MR. BRETT: Excuse me, Tom, Tom Brett here. I Just want to help clarify. You are looking for the interrogatory and it is a BOMA interrogatory that deals with the unidentified efficiencies of 12 million. It is actually 23D. And there's an answer, 23D as in dog, there is a fairly lengthy answer that talks about the need to reach a certain ROE target and the necessity for the unidentified, and I'm paraphrasing, savings is to reach that target. In other words, it is sort of what you said at the outset.

CONTINUED QUESTIONS BY MR. LADANYI:

MR. LADANYI: Thank you.

So if you turn to FRPO number 1, attachment 2, page 12. You've got it? Under "management functions" and "other", what is "other"?

MR. MILLAR: Sorry, Tom, what page are you on?

MR. LADANYI: We're on page 12 of 12. We've been on this chart several times today. It is on the screen. If you can just turn over and have a look at it.

MR. PACKER: Mr. -- I'm trying to be helpful. If you look at BOMA 16, page 8 and 9, "management functions" and "other" are separated, and there is a description of what each is on those pages.

MR. LADANYI: BOMA 16? Which page, sorry?

MR. PACKER: This is BOMA 16, attachment 1, page 8 and page 9,

MR. LADANYI: So the cost that I see there, potential capital investment, I think we mentioned this before, so this would be -- include in it severance for people who are going to be let go?

MR. PACKER: No, sorry, the capital costs do not include severance. The $150 million is the capital costs to do the system work to amalgamate the two utilities.

MR. LADANYI: I recall a different answer earlier today, but I won't follow up on it. Very good. If that's the case.

MR. PACKER: I think there are references to 170 million and how you reconcile the two is 20, but if you are looking at a capital cost schedule that shows 150, that is just capital cost.

MR. LADANYI: So when you look at potential O&M savings between 170 million and 150 million, how many employee reductions would that be, FTE reductions, assuming let's say each one is 150,000 per employee? Or you can give me your own estimate.

MR. REINISCH: Unfortunately with respect to the detailed planning on other functions, that work is not being conducted, so there is no ability to provide a response.

In order to be helpful with respect to the management function savings, that information is contained on BOMA 16, attachment 1, pages 8 and 9. There is a breakdown at a high level of how the savings were arrived at for management function rationalization.

MR. LADANYI: Okay. I will leave it at that, and Mr. Yauch has a question. No?

MR. MILLAR: Is that it, Mr. Ladanyi?

MR. LADANYI: That's it. Thank you.

MR. MILLAR: Thank you so much. Mr. Garner?

QUESTIONS BY MR. GARNER:

MR. GARNER: I will try and be quick too, but I would just like to follow up on what's being talked about, and I think it really comes down to this issue that keeps coming back and forth, is whether the numbers for the savings and the expenses are bottom up, are up down, if you know what I mean.

So Mr. Charleson, you said you are a member of the senior executive. Do you report to Mr. Sanders? Is that you direct report?

MR. CHARLESON: Yes, I report to Mr. Sanders.

MR. GARNER: Is there anybody else on the panel from Enbridge who directly reports to Mr. Sanders?

MR. CHARLESON: No.

MR. GARNER: Is there anybody on the panel that directly reports directly to Mr. Baker?

MR. PACKER: I report directly to Mr. Baker.

MR. GARNER: Okay. Thank you. So maybe I'll then address it to the two of you at the back.

At any time during this process were you provided or told that there were objectives of Enbridge Inc. to make for savings for this amalgamation?

MR. CULBERT: I wasn't.

MR. CHARLESON: No, there was nothing specifically that came from Enbridge Inc.

MR. GARNER: Was there anything generally, as opposed to specifically then?

MR. CHARLESON: Nothing that...

MR. GARNER: Okay. Thank you.

Now, I want to go to a couple of other things that were here, and let me just pull up my IRs and see where I'm at.

If you look at, I think it's BOMA 5, and you don't really have to pull -- I mean, well, you can pull it up, but BOMA 5 you were asked, I think, about whether -- whether the purpose of the merger was to increase profitability, and in essence you say that's not confirmed, which kind of says that's not the purpose.

But I wanted to explore that, because, are you trying to say in this response that the utility is not attempting to increase its profitability as part of this merger for the benefit of its shareholders? I mean, I know you are saying there is benefits to ratepayers, and I'm not talking about those, but are you trying to say you are not trying to achieve benefits to the shareholder as part of this amalgamation in that response?

MR. KITCHEN: I don't think we are saying that at all. But it's clearly not the major goal of the amalgamation. We are, of course, trying to produce the best outcome for the shareholder, but if you look at -- if you look at the board of directors' presentations, one of the things that jumps out at you is that over the term of the ten-year to firm rebasing period we are averaging 20 basis points above our allowed, and that -- we need the synergies, actually, to get that.

MR. GARNER: Right. Thank you. And I wanted to bring you to that exact point, which I think is done at C Staff 57, where you lay out in that interrogatory -- and I just wanted to explore that with you. I think that's -- what that's showing is the 20 basis points that you are talking about achieved versus allowed, and I wonder if Bonnie can bring it up.

You will see a little table down there, 2019 through 2028. It's -- I think it's C Staff -- I think it's 57. Oh, no, I'm on the wrong place. And now I've lost it, because I was on 57. It's C Staff 2, maybe, page 6. Let me just see if that's the right reference.

No, unfortunately I -- yeah, is it -- because I just lost it. I just had it on my screen and now I've just lost it.

Yes, it is, thank you, Andrew. That is exactly where it is.

So it's got a table, and I believe that's what -- just below that -- keep going. That table there.

Mr. Kitchen, is that what you are driving at? That's the table that shows the 20 basis point sort of goal or achievement in order to -- in order to make it worthwhile, so to speak, call it that way, of the amalgamation, so it is slightly above the allowed rate of return that you are trying -- you are showing to achieve here.

[Witness panel confers]

MR. KITCHEN: That's correct, that's the table that I was referring to, and, you know, I think that, you know, this demonstrates, I think, that one of the reasons that we need the ten-year deferred rebasing period is in order to actually get -- make the investment, get the synergies, and pass on some benefit to ratepayers while still providing a benefit to shareholders.

MR. REITDYK: And I'll add as well that this is something that we've talked about openly as being a win-win situation. You know, there are a number of us who have long histories with both Union and EGD and over the past 15 to 20 years, we've worked very hard to drive productivity improvements and keep rates as low as possible while maintaining our profitability.

And in the course of that, what we see right now is diminishing returns on those productivity improvement efforts.

If you take a look at everything we've done over the past, we are really starting to run out of ideas individually on things to do. And this framework affords us the opportunity to -- the next best chance to drive a step change in productivity improvements that otherwise wouldn't be available to us.

MR. GARNER: And certainly I'm sure the people at Union Gas are just waiting for your productivity improvements and vice versa for the other side, so I'm sure it will be a very interesting time for both you.

But the reason I'm asking the question was if these were then -- I want to bring this to your ESM and I understand your ESM proposal, your earning sharing proposal, is basically based on the concept of the Board's guidelines for electricity. That is correct, isn't it? That's the 300 basis point over whatever -- you used that as your model for this one, is that correct?

MR. CULBERT: Yes, it's based off the principles and goals and objectives of the MAAD principles, yes.

MR. GARNER: And it is get quite different, as was brought up before, between the ones that you are both under -- using right now. You are both using slightly different versions of an ESM proposal, so it is not the same as the current version either one of you have, right?

MR. CULBERT: That's correct.

MR. GARNER: So it kind of begged this question to me when I looked at this. Well, if this is what you are hoping to achieve, then why would the ESM be needed as long as you are making these returns that you've projected for yourself as being required? I mean, what's needed more than what you are putting down here? Why do you need an ESM any more than is capped by these numbers, which are the numbers that you are projecting yourself in order to make this a worthy goal for the utility, and I've heard now from the shareholders' point of view and from the ratepayers' point of view.

And just colour it a bit, because when I read those policies for the board and electricity, they do go into some things about electricity that seem to be specific. But we can have those arguments in some other forum.

What I was trying to figure out is, well, these seem to be the numbers you could live with. Why is that not a correct interpretation?

MR. KITCHEN: I think that, first of all, the reason we've adopted the earnings sharing mechanism that's contained in the evidence is because that is per the rate handbook.

Second, if you look at Board Staff 4, we talk about the fact that the Board has stated that earning sharing mechanisms protect customers from excess earnings, but they can also diminish incentives. And what we want to have is the incentive to go out and pursue as many of the savings as we can, and we want to be able to do that in such a way that we maintain safe and reliable service.

MR. GARNER: Fair enough. Thank you. I want to change gears completely for now, and I want to look at the response to Board Staff 3 and the table that was brought up in the FRPO response from the presentation. And it's the one that had the integration of opportunities in the summary.

And the reason I'm only bringing that up -- I know you can't see both of them, or maybe you can in your own notes and then Bonnie can show you one.

The numbers there are similar, but they're not quite the same, partly because you are taking a point estimate here and partly because the other one -- this table in that response is it a range estimate.

I know this may seem quibbling, but I couldn't figure out how you got to the point estimates versus the range estimates because they are not always just the equidistance point, right? They seem to actually be informed by some other slight concept. It is not always equal; it is not always the same. So I couldn't pattern it from one to the other.

MR. KITCHEN: I think the place to go to look at that is in the -- well, you can look in the appendix to BOMA 16(C) and it's there. But also in the words, we've actually set out how we landed on those points.

MR. GARNER: Fair enough. I'll take a look at that. My next question -- let me just pull up my IRs here.

This has to do with -- and you may not be the right panel, and you can tell me that. Let me start the question this way. When this amalgamation is approved, if it's approved, is it the intent of the amalgamated utility to rebrand?

MR. KITCHEN: We have not had a single discussion about that.

MR. GARNER: Let me suggest to you it is going to be an odd amalgamated utility to have two company names on it, since most single companies have a singular name and not two names. Right?

MR. KITCHEN: There will definitely be a single name. What that is we have not talked about.

MR. GARNER: Right. The only reason I'm asking that is because it goes to the next thing I asked in this interrogatory about bordering areas and that, and this is in VECC Interrogatory No. 36. You answered the interrogatory very well, but I don't think you understood my concern or the thing I was trying to get at.

You answered this interrogatory with respect to something called exchange agreements. This is about customer -- where you would join -- the utilities that join each other, and you answered with this response about exchange agreements -- which was very interesting, because I didn't realize you had such an agreement with each other where you basically transferred, I guess, gas and other things because you're overlapping and maybe not even -- I take it not even at metered points; is that right? They can be non-metered, or are they always at a metered point where you exchange under these exchange agreements?

MR. KITCHEN: No, I think the way the exchange agreements work is that if -- along the boundaries, if it makes sense for Union to serve a customer and they are technically in the EGD area, we will serve the customer and then we just do a transfer at Dawn for the gas with the customer.

They'd be billed as an EGD customer, but we would serve them.

MR. GARNER: So in electricity, they call that load transferring, which is one customer is serving the other -- one utility is serving the actual product, but the other utility is billing the actual product.

MR. KITCHEN: It is more economic for us or for EGD to serve a customer, depending on where they're located.

MR. GARNER: I am familiar with the argument in electricity, and now I see what you were getting at.

The reason I asked this question, and then I asked another question which was, I believe, either above or below this that you actually said you wouldn't answer was I wanted to understand this: What is the impact or what is the potential problem of adjoining customers who now are served by two different utilities who will be under the rebranded singular utility having different rates, but being served by the same utility?

So what I was trying to understand is how large could the problem be or not be of customers who are now served by -- let's call it...

MR. KITCHEN: Amalco.

MR. GARNER: It's a lovely name, Amalco. And they are now being served by Amalco, but with their neighbour they go over and they find out, well, I am not actually getting the same rate; how come? I've walked across the street and how come I'm not getting the same rate as my friend over here. We are no longer Union and Enbridge.

So I was trying to get an understanding of how much and how large you had overlapping territories where that problem might occur, and how many customers you had actually thought about that might occur to.

Do you have any idea to help me with that?

[Witness panel confers]

MR. KITCHEN: It might help us if we try to clarify the request because it really depends, I guess, on do you want customers that are on opposite side of the streets?

Do you want customers who are within a kilometre of each other?

MR. GARNER: That's a good question and a fair one, because what I'm really trying to do -- and I know you are at a very preliminary stage with this whole exercise. But what I'm really trying to understand is to what extent does that problem potentially exist. And to me, that would be people who are within communication of each other, bordering each other would be probably the biggest thing.

And also, I was thinking when my request here was that you would deal with those large population centres as opposed to the small ones, so I wasn't trying to go down through all of Ontario and find out every street you were next to, but there were areas where would you have large groups of populations within each other, so Brampton would be an area, Oakville, Burlington would be an area, outside of Ottawa might be areas, right? You would have these areas where you were going to abut with large groups of people who might find it disconcerting, and that went to a -- I'll to go my next question -- disconcerting that they were being charged different rates even though they were served by the same utility.

MR. CULBERT: So those situations exist now in the electricity sector, right? I am on Hydro One and someone right across the street from me is paying at a low-density rate or I am paying at a low-density rate and they're paying at a medium-density rate. Same company.

MR. GARNER: Yeah, I'm sure it is, and I'm sure the

Board would be happy to hear you use that as the example of continuing such an operation.

So it doesn't really answer my question, though, because I'm still just really trying to figure out how large could that problem be, and anything that you could help us with that would be helpful. And before you answer, Mark, just let me ask you the next one, because it was a question you didn't answer that kind of went to the second part of this, which might help me understand whether this is a big enough problem.

We asked you basically to put together a table of rates, basically using Enbridge and Union, and compare those rates. Now, you did one -- we also asked you to do something with volumes, which you did, and give us a bill kind of concept.

And then you basically said, well, we are not proposing to change rates, so we are not going to give you a table that compares them. Now, that seems to me odd, because the Board, one of the things looking at this is going to want to answer, it seems to us, the same question, which is, are customers going to be charged by a singular utility largely different rates, and where, and how, because the Board is going to run into this problem, potentially, and we're going to see -- certainly suggest to them that you might run into this problem of customers who are dissatisfied with the arrangement of this singular utility.

So both of those would help. One is, show us the rates and compare them so we can understand what the difference is, and then provide us with an analysis of how much of the population or where in the province do you think you are going to have issues with customers served under a singular utility.

And to make this easy, because Mr. -- we're running -- you know, this is -- this is a tough request, I understand that, and it may be hard for you to even answer. What I would ask you to do is, if you could think about it overnight, maybe give it some thought, without giving an undertaking, and then tell us tomorrow if there is anything you think you could do that would help deal with what I think is a reasonable concern and request.

Would that be satisfactory, Mr. Cass?

FOLLOW-UP QUESTIONS BY MR. AIKEN:

MR. AIKEN: It is Randy Aiken. Can I jump in for a minute? There is a comparison of the cost to different types of customers in LPMA 42, attachment 1.

MR. GARNER: Thanks, Randy, I'll look at that. Thanks.

MR. AIKEN: Okay.

MR. MILLAR: Okay. So where are we leaving this?

MR. KITCHEN: I almost have to read the transcript to find out exactly -- there was a lot -- there was a lot said that --

MR. MILLAR: There was an offer to think about it overnight, and is that what we need?

MR. GARNER: Right. There are only two requests, Mark. Request 1 is, could we have a rate schedule -- or rate schedule that shows for both utilities the comparison for like areas? I know for each one of the rate classes showing all of them and what the rates are for all of them so we can compare, which seems to be all public anyways, it is just a matter of putting it into a table.

And the second request was, could you provide an assessment of where the two utilities have large groups of customers who abut, would be the word, maybe, adjoin in the same area and how large of a -- how many customers roughly are in those areas. Is that succinct enough?

MR. CASS: Excuse me, and Mark, both aspects of that are what you are suggesting that we would think about overnight? Is --

MR. GARNER: Yes, exactly --

MR. CASS: -- report on in the morning?

MR. GARNER: -- because I know the -- especially the second might be difficult to do, and it may not even be possible to do.

MR. CASS: No, I can't think of any reason why we wouldn't consider it overnight and let you know in the morning the outcome our thought process. So yes.

MR. MILLAR: Mark, do you need that undertaken --

MR. GARNER: No, I don't. I think tomorrow Mr. Cass will address it --

MR. MILLAR: Do you have more questions, Mark?

MR. GARNER: I do. VECC --

MR. MILLAR: I just know we are getting short on time.

CONTINUED QUESTIONS BY MR. GARNER:

MR. GARNER: I think this will be my last question. VECC 27, I think is the question, and the IR. And that interrogatory, I believe -- see if I can find it. VECC 27. Oh, this was -- it was about the NACC adjustments that both utilities are suggesting in their deferral accounts, and this is really a confusion of -- I am trying to figure out something myself in your plan.

When you have the NACC adjustments that you currently have and you propose to move forward, is the effect of the NACC adjustment in your plan to give you -- to take away the forecast risk of the utility? Tell me what risk is mitigated by that NACC adjustment for you?

MR. KITCHEN: Well, the NACC deferrals, I think in both utilities -- Kevin can correct me if I'm wrong -- deals with general service volumes, and it is really there to recognize decline -- it really started to recognize declines in average use as a result of things such as DSM and, you know, building code changes and such, and so really what it does is it continues to do that, it continues to do that with respect to carbon.

MR. GARNER: But does it do it also, I guess, Mr. Kitchen -- this is where I was wondering, does it also do it for weather generally, because that also becomes an input into the average use?

MR. KITCHEN: No, because the NACC, as I understand, and maybe -- I'm sure you could use the same, so it's normalized.

MR. GARNER: Right. That's what I was wondering. So you can sort of exclude weather from it, and it is just the trend, as you say, in these other factors.

MR. KITCHEN: That's right --

MR. CULBERT: Attempting to model the average use per our model, per Union's model, as accurately as possible.

MR. GARNER: Thank you, those are my questions.

MR. MILLAR: Thank you, Mr. Garner.

Anyone else in the room with questions. Unifor, please.

QUESTIONS BY MR. VALENTE:

MR. VALENTE: Unifor, Dan Valente. Panel, just with respect to BOMA 16, attachment 1, seems to be the flavour of the day, turn our attention to page 6 on the net O&M savings assumptions. Just a couple of questions.

And we've heard today that, you know, these are high-level range of potential savings that were done by your colleagues' senior leadership meetings. We don't know who they were, but they did take place, and I just want to know at a high level under customer care, what's the head-count impact that is built into the -- into this range of savings?

MR. CHARLESON: At this time there has been no head-count impacts identified.

MR. VALENTE: Okay. Because I heard today that we do understand that customer care is made up of systems and people, and you're going to save money on people, which would be a head count.

MR. CHARLESON: Yes, but at this time we still have to do our detailed integration planning. We have to understand where we had from a systems perspective worked through those things. And until we really understand all that, we can't even start to assess what it means in terms of our workforce composition or how we execute the work.

MR. VALENTE: Okay. Well, I --

MR. RIETDYK: Just to clarify, I don't think we are saying that the savings are all people-related. There's a number of system and other savings related as well.

MR. VALENTE: No, no, that's correct, Paul, I understand that. But I just, like, at a high level I've been asking this question at numerous different tables, you know, and the same is with the distribution work management, right, so is there a high-level head-count impact? Because I take it that this -- if I heard correctly today, the distribution work management that we are speaking of here is the back office; correct?

MR. RIETDYK: That's correct. And again, it could be made up of a mix of systems, third-party services, and employees, costs, so it could be a mix of those and we haven't turned our heads to do any kind of detailed analysis of ultimately where that would be.

MR. VALENTE: Okay. Well, in the first paragraph under the distribution work management, the last line talks about increased savings between 2024 and 2028 due to optimizing third-party contracts.

Who are the third-party contracts?

MR. RIETDYK: So an example of that would be our construction alliance partners.

MR. VALENTE: So they are not back office, though.

MR. RIETDYK: No, but they are included in the scope of distribution work.

MR. VALENTE: Okay. So now I understand that statement, because now we are talking about, we are moving into the field, right, like, from 20 -- the date there, right?

MR. RIETDYK: That's correct, it's in the second half of

MR. VALENTE: Right. The second finding. Okay. Thank you.

MR. BRETT: Could I just add a follow-up there?

MR. MILLAR: Quick.

FOLLOW-UP QUESTIONS BY MR. BRETT:

MR. BRETT: Are you saying that there are no employee savings -- no savings as a result of employees leaving in those numbers, in those tables? In other words, the converse to what you just said. Are there any dollars in there attributable to employees being let go, or however you want to call it, or are those going to be additional dollar savings to you over and above what you have in those tables?

MR. CHARLESON: No, what I indicated and I'm hoping I conveyed is we haven't identified how we are going to achieve those savings. There is a lot of work that has to be done in terms of planning. There's definitely savings that we expect to see come from systems and integration of those types of things. But then we do have to assess how the work is being done and are there opportunities that way. But we haven't done any planning at this time, and so we can't say one way or another, in terms of what component or what may or may not arise from, say, adjustments to the workforce.

MR. VALENTE: Which I find interesting, but the next question is on storage and transmission operations, gas supply and control. Once again, any high-level head count impacts?

MR. REINISCH: It is the same answer. We haven't done any kind of detailed assessment planning of that function. Again, these were high-level macro savings that have been identified.

MR. CHARLESON: Again, Dan, as you look at BOMA 16 in the section for the savings, it does indicate primary cost savings expected to come from harmonizing the SKADA system for one.

MR. VALENTE: Right. Let's be honest, the use of the word synergies in the application that the utilities put before this Board, you talk about workforce restructuring and alignment, okay?

I'm sorry, being a Union guy, synergies means potential job losses, so let's be open and honest. And I just want to point out that how is it under the management functions, the senior management did turn their attention to high-level head count. In talking, they used a

25 percent reduction of an estimated base of 450 combined. Can you explain that one?

MR. KITCHEN: I think the simple answer is it's an easier group to look at and identify savings.

MR. VALENTE: Okay. That's all my questions.

MR. MILLAR: Thank you very much.

Anyone else in the room? No. Randy, you have one or two questions. Do you want to go?

QUESTIONS BY MR. AIKEN:

MR. AIKEN: Okay, I have two questions. The first one is on FRPO 11. I don't know that you actually need to turn it up, but it is table 1 for Enbridge and table 5 for Union, and it's line 3.1, "capital expenditures." And I take it that these numbers come from your distribution system plans over the ten-year period.

My question is a two-parter on this one, and that is am I correct that there are no capital expenditures related to the integration cost included in these numbers in these tables?

MR. REINISCH: That is correct, there are no integration-related costs.

MR. AIKEN: And the second part of that same line item is: Are there community expansion costs included in those numbers?

MR. REINISCH: Yes, there are capital costs associated with community expansion in those numbers.

MR. AIKEN: Okay, and then my second question, my final question --

MR. KITCHEN: Randy, I just wanted to add one thing to that. One second....

[Witness panel confers]

MR. REINISCH: Sorry, the other thing I wanted to note is that in table 1 and table 5, the revenues associated with those communities that are considered community expansion are also included.

MR. AIKEN: Yes, I noticed that. Thank you.

My other question deals with the integration capital investment, this range of 50 to 250 million, and the statement -- and this is in CCC 2 -- that this is investment of a shareholder, but the shareholder's risk in that basically ratepayers will not pay for any of this.

So does that mean that by the end of the deferral period, these capital investments will either fully depreciated, or if they are not fully depreciated, any remaining net book value will be tracked separately so it can be kept out of rate base?

In other words, how do we ensure that ratepayers do not pay anything beyond the deferral period?

[Witness panel confers]

MR. REINISCH: Sorry, I cannot confirm that. Again, the capital investments will be at the risk of the shareholder during the deferred rebasing period. Upon rebasing, though, the benefits of the activities will accrue to the ratepayer. And at that point in time, whether there is any residual rate base or not will have to be assessed and will be deliberated before the Board.

MR. AIKEN: It will be determined as part of the rebasing application?

MR. REINISCH: That is correct.

MR. AIKEN: Okay, thank you. Those are my questions.

MR. MILLAR: Thank you, Randy. Scott, are you still there? Do you have a question or two left?

QUESTIONS BY MR. POLLOCK:

MR. POLLOCK: Yes, so I will be very quick. I just have two interrogatories.

If you could pull up CME 2 -- and because I am on the phone, if you could let me know when that is up, I would be much obliged.

MR. MILLAR: It is up.

MR. POLLOCK: All right, great. So the original application stated that field operations were excluded from the scope due to the fact that the service areas for each utility don't directly overlap.

And in response to the IR, you gave what I thought might be a second reason, which is the focus of the amalgamation is to bring together systems and processes that will allow time for field operation procedures to be harmonized.

I just wanted to know for my own clarification is this a second independent reason for why field operations have been excluded, or is there a relationship between the service area is not directly overlapping and the time to bring systems and processes together?

MR. RIETDYK: I think it is both of those, and I spoke to some of those things earlier in terms of the practical requirements to -- before we can bring field operations together, and we need the systems and the processes to be aligned and we need the procedures and detailed work instructions to be aligned as well, and that's going to take some time.

Once that's done, then I think we can consider it. But in the meantime, we need to stay focussed on delivering safe and reliable service for our customers and that, I think, will minimize any of the risk associated with safety and reliability.

MR. POLLOCK: So is the overlap or lack thereof, does it increase the time it takes to get all the processes together, or is the relationship there, just so I'm clear?

MR. RIETDYK: First of all, there is not a direct overlap. We're adjacent to one another in a number of different areas and in addition our main offices, we have a number what we call depots or branch areas within the larger areas, just to minimize travel time for our employees. So we are trying to optimize the work locations to where they actually physically work in the field.

As mentioned before, the business is very much a geographically based business. We work on our customer premises in our system within the geography itself.

So the fact that they're adjacent isn't going to lead to many synergies down the road. There may be some on the edges of our service territories, but I think that's it.

MR. POLLOCK: Thank you. Could you also pull up CME number 4, and let me know when that's up?

MR. MILLAR: Its up, Scott.

MR. POLLOCK: Thank you very much, sir. So in terms of this part (b) of our interrogatory asked if the answer was yes, if you had done initiatives like this before, what were the actual savings as a result of the campaign.

And in your answer, you gave sort of a principled understanding of the cost savings, but not the actual results of any specific campaign. So I guess I was wondering if either of the utilities track the results of e-billing campaigns?

MR. CHARLESON: We would keep a general eye in terms of some of the outcomes from some of our e-bill campaigns. But the difficulty you get into is there's going to be -- it's hard to identify whether the adoption that occurs while a campaign is going on is directly as a result of that campaign, or through other messaging or customer behaviours that have triggered it.

So that's where we felt it was more beneficial just to identify kind of the financial impact that arises from -- from successfully moving more customers to e-bill.

MR. POLLOCK: Understood. To the degree that it's acknowledged that there is a little bit of a buyer beware type of thing with this, would you be willing to provide whatever tracking you do for the e-bill campaign?

MR. CHARLESON: We'd have to look into what we may have.

MR. POLLOCK: Okay. Could you do that for me?

MR. CASS: Scott, I'm not really sure how this is going to be helpful to the Board in the context of the application. There may be some interesting information, but it is escaping me how this is going to help the Board rule on the MAADs application and the rate mechanism.

MR. POLLOCK: Well, I guess my thought was that if one of the central aspects of this application is the benefits to ratepayers, the degree to which they were -- could have and already and will continue to gain some of these benefits even absent the amalgamation might be relevant.

MR. CASS: I'm sorry, Scott, I'm just not seeing the connection between the work that you are asking to be done to turn up this information and the issues that the Board will need to decide in this case.

MR. POLLOCK: Okay, fair enough.

And one final question. In terms of -- I don't think you need to turn it up, but in one the FRPO interrogatories that I asked you about, the productivity that was built into the non-amalgamated revenue requirements for the two utilities, and I was just wondering if the productivity that was embedded into those forecasts included initiatives such as, you know, increased e-bills?

MR. KITCHEN: Could I have the reference? Like, it would be helpful if we turned up the FRPO IR.

MR. POLLOCK: FRPO -- I believe it was 10 or 11. Let me just...

MR. REINISCH: If it would be helpful, I believe it is FRPO 11C.

MR. POLLOCK: Okay. Thank you.

MR. REINISCH: So, yes, the efficiencies from any increase in e-billing would not be included in the base case.

MR. POLLOCK: Okay. Thank you very much. Those are my questions.

QUESTIONS BY MR. MILLAR:

MR. MILLAR: Thank you, Scott.

Anyone else on the line with questions?

Okay. I just have one thing which will be very quick. It's not a Board Staff question, but there was a letter of comment that came in the other day, and I thought I might address it to this panel. It is from a Mr. Blackmore, and rather than try and paraphrase I am just going to read it and hopefully you can respond. It says:

> "With this new company being formed, almost every town and company in Ontario will receive its natural gas from this one company. My question is, will it be monitored and operated in a control room in Ontario as Union Gas does or will it be monitored and operated from Edmonton, as Enbridge Gas currently does?"

MR. CHARLESON: So at this time we don't know what our control-room environment will be. We will obviously be looking at the merits of different operating models for that, so can't speak to where it may reside. However, you know, we will continue to ensure we have the right resources on the ground for monitoring and administering our distribution system to ensure safe and reliable distribution.

PROCEDURAL MATTERS:

MR. MILLAR: Okay. We will leave it at that.

Thank you very much, panel. We are done for the day. Thank you to the court reporter for her patience. We are done back at 9:30 tomorrow morning with panel 4.

And then I should alert parties, we are not looking to sit late tomorrow. It is the last day before a long weekend, and people have commitments at the end of the day, so we will be wrapping up probably by 4:00 at the latest, I would suggest, tomorrow.

And after panel 4, it will be panel 3, correct?

[Microphones not activated]

MR. MILLAR: We have given our estimate for panel 4, but that's it.

[Microphones not activated]

MR. MILLAR: If you have an estimate and you want to give it, please do so. Thank you. We are adjourned.

--- Whereupon the hearing adjourned at 5:12 p.m.

TAB 5

Labor Calculation

Description
Calculates Labor Price for Union for each year

Labor Calculation

Sources	Summarized Union data tab

Year	Company	Distribution FTEs (a)	Distribution Wages and Salaries (b)	Labor Price (c) = (b)/(a)
2000	Union Gas Limited	2,188	129,826,912	59,327
2001	Union Gas Limited	2,128	131,023,949	61,564
2002	Union Gas Limited	1,986	135,761,449	68,369
2003	Union Gas Limited	1,962	134,327,731	68,451
2004	Union Gas Limited	1,878	126,533,398	67,372
2005	Union Gas Limited	1,877	132,056,491	70,346
2006	Union Gas Limited	1,882	135,406,546	71,959
2007	Union Gas Limited	1,925	147,356,076	76,559
2008	Union Gas Limited	1,973	154,441,241	78,271
2009	Union Gas Limited	1,957	156,943,533	80,195
2010	Union Gas Limited	1,982	164,279,784	82,881
2011	Union Gas Limited	1,989	171,978,533	86,452
2012	Union Gas Limited	1,958	164,431,437	83,983
2013	Union Gas Limited	1,956	180,876,510	92,467
2014	Union Gas Limited	1,991	189,216,112	95,031
2015	Union Gas Limited	2,021	188,408,807	93,241
2016	Union Gas Limited	2,037	188,048,849	92,325

TAB 6

Year 2000

EMP&CWR Headcnt @ Prompted Dt	4			
Org Relation	Reg/Temp	Full/Part	Sum FTE	Sum Annual Rt
EMP	R	F	1700.300000	76830946.778
EMP	R	P	33.260000	828526.170
EMP	T	F	35.880000	935228.116
EMP	T	P	38.790000	1109483.128

Year 2016

EMP&CWR Headcnt @ Prompted Dt	4			
Org Relation	Reg/Temp	Full/Part	Sum FTE	Sum Annual Rt
EMP	R	F	1925.000000	166847995.632
EMP	R	P	29.340000	1830879.334
EMP	T	F	91.000000	6111628.432
EMP	T	P	6.970000	367809.520

TAB 7

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2001-0032

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, C.15, Sch B;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc., formerly The Consumers' Gas Company Ltd., for an order or orders approving or fixing rates for the sale, distribution, transmission and storage of gas for its 2002 fiscal year;

AND IN THE MATTER OF a motion by Enbridge Gas Distribution Inc., for review and variance of the decision of the Board as set out in its RP-2001-0032 Decision with Reasons dated December 13, 2002.

BEFORE: Bob Betts
Presiding Member

George Dominy
Member

A. Catherina Spoel
Member

DECISION WITH REASONS ON MOTION

On January 7, 2003, Enbridge Gas Distribution Inc. ("EGDI") filed a notice of motion, pursuant to Part VII of the Board's Rules of Practice and Procedure (the "Motion"), asking the Board to review and vary its decision in the RP-2001-0032 proceeding ("Decision"). During the RP-2001-0032 proceeding, EGDI was carrying on business under the name Enbridge Consumers Gas.

By letter dated January 9, 2003, the Board directed EGDI to file, by January 17, 2003, all of the supporting documentation EGDI intended to rely on, including its submissions on the merits of its motion, which EGDI subsequently did.

In its Motion, EGDI asks the Board to review and vary its decision with respect to two issues. EGDI asked for the following relief:

(a) a review and variance of the Board's finding that the Alliance 1 and Alliance 2 contracts were not prudent;

(b) a review and variance of the direction to Enbridge Gas Distribution Inc. to credit $11.0 million to the 2002 Purchase Gas Variance Account ("PGVA") and provide the Board with sufficient evidence of this credit when dealing with the clearance of the 2002 PGVA in the 2003 rates proceeding;

(c) a review and variance of the Board's comments and findings in secion 5.11 of the Decision to confirm that:

  (i) the duty of Enbridge Gas Distribution Inc.'s management to act in the best interests of the corporation equates to a duty to act in the best interests of the shareholder, and not in the best interests of the ratepayers;

  (ii) the shareholder of Enbridge Gas Distribution Inc. has the right to not only earn a fair return on its invested capital, but to undertake commercial transactions, and reorganize assets and services, in furtherance of corporate business interests, provided the ratepayers of the regulated utility are held harmless from the consequences of such transactions; and

(iii) the Board (and not Enbridge Gas Distribution Inc.) has an obligation to balance the interests of the utility shareholders and utility ratepayers;

and conversely, that Enbridge Gas Distribution Inc. has no obligation

(iv) to bring critical operational issues to the Board's attention; or

(v) to act in the best interests of the ratepayers, thereby conferring upon them a benefit, significant or otherwise;

(d) a generic hearing to examine the issues fully in the event that the Board decides to change its policies on the application of the "no harm" test, or decides to make changes to the *Affiliate Relationships Code for Gas Utilities*;

(e) an order of the Board itemizing all directives to Enbridge Gas Distribution Inc. (the "Directives") that arise from the Decision and stating the statutory authority pursuant to which these Directives are issued;

(f) a stay of the Directives in paragraph (e) above, pending a final determination of this motion; and

(g) such further and other relief as the Board may deem just.

In support of the Motion, EGDI filed the affidavits of Rudy Riedl, Janet Holder and Marika Oksanna Hare, along with its submissions.

Section 44.01 of the Rules of Practice and Procedure states:

44.01 Every notice of a motion made under Rule 42.01, in addition to the requirements under Rule 8.02, shall:

(a) set out the grounds for the motion that raise a question as to the correctness of the order or decision, which grounds may include:

(i) error in fact;

(ii) change in circumstances;

(iii) new facts that have arisen;

(iv) facts that were not previously placed in evidence in the proceeding and could not have been discovered by reasonable diligence at the time; and

(b) if required, and subject to Rule 42, request a stay of the implementation of the order or decision or any part pending the determination of the motion.

In effect, EGDI is asking for relief on two issues. The first issue relates to the Board's finding that EGDI had not proven the prudence of its decision to enter into the Alliance contracts and the Board's disallowance of $11.0 million in relation to those contracts. The second issue is the Board's expectations regarding the evidence to be filed by EGDI in relation to its outsourcing arrangements, in the upcoming rates case, the RP-2002-0133 proceeding.

Having considered the Motion and the supporting material filed by EGDI, the Board finds that EDGI has not established that there are errors in fact, changed circumstances, new facts, or evidence that was not reasonably available at the time of the hearing which would raise a question as to the correctness of the Board's Decision.

Therefore the Board finds that it is not necessary to hear from the intervenors on this Motion, and that the Motion should be dismissed.

The Alliance Contracts Issue

There are two aspects to this issue. The first is the prudence of the decision to enter into the Alliance contracts. The second is the Board's disallowance of $11.0 million in relation to the contracts.

(1) <u>The prudence of the decision to enter into the Alliance contracts</u>

The onus to establish the prudence of the Alliance contracts was on EGDI. In its Decision, the Board concluded that EGDI had not discharged this onus. In support of the Motion, EGDI filed the affidavits of Janet Holder and Rudy Riedl. Janet Holder had already testified during the course of the hearing. It was always open to EGDI to file additional evidence or call Rudy Riedl or others as witnesses. (See, for example, UNDERTAKING NO. G.3.14: to provide any internal documents, memos, or other materials as well as minute action items from board of directors' meetings which would assist in confirming that Enbridge Consumers Gas acted prudently when entering into these various contracts.) Having reviewed the material filed by EGDI, the Board is of the view that there is nothing new in the two affidavits that could not have been put on the record during the course of the hearing and therefore EGDI has not met the test under Rule 44.01.

(2) <u>The Board's disallowance of $11.0 million</u>

The Board is not convinced that the amount of the disallowance should be changed. The usual consequence for a utility that has not proven the prudence of a decision it has made is that all of the costs associated with that decision will be disallowed. In this particular case, the Board did not apply the usual consequence. Rather, the

Board disallowed, on a one-time basis, $11.0 million of the costs incurred in connection with the contracts.

The issue of prudence and potential disallowance was first addressed in the Settlement Proposal (Gas Costs) dated September 1, 2000 filed in RP-2000-0040 (EB-2000-0234), Exhibit N1,Tab 1, Schedule 1, Page 5 of 8, which states:

- ECG concurs with the other parties that ECG's proposal to include the entire cost consequences of ECG's agreements for transportation services on the Alliance, the Link, and the Vector Pipelines is in issue for examination during, or settlement prior to, the Board's oral hearing in the main RP-2000-0040 proceeding; and

- ECG's gas cost forecast or its revenue requirement, as the case may be, will be adjusted as required by the Board's decision on, or the settlement of, this issue in the main RP-2000-0040 proceeding.

The issue was next addressed in much the same way in the Settlement Proposal (Gas Costs) dated November 28, 2000 filed in RP-2000-0040 (EB-2000-0317), Exhibit N1,Tab 2, Schedule 1, Pages 4 and 5 of 7, where EGDI's cost recovery on the Alliance, the Link and the Vector Pipelines was acknowledged as an outstanding issue.

In the RP-2000-0040 main rates proceeding, EGDI and the other parties agreed that the prudence and any potential disallowance would be deferred and that it would be open to any party to raise these issues in a subsequent rates case. In the Settlement Proposal (Main Case) dated May 11, 2000, Exhibit N2, Tab 1, Schedule 1, the parties further agreed as follows:

At pp. 10 and 11 of 54:

> ECG and the other parties concur that an examination of this issue would be facilitated by quantifying, during the Test Year, the cost differential between the two transportation paths [EGDI's traditional transportation path and the new path involving the Alliance and the Vector pipelines] by means of a notional deferral account. The resultant entries in this account, together with the other information ECG will provide as a condition of this settlement, would provide an evidentiary basis for a thorough examination of this issue in ECG's next rates case. [context added]

At p. 12 of 54:

> The cost differential recorded in the notional deferral account for the Test Year will be examined in the context of ECG's next rates case as a means, among others, of ascertaining whether the entire cost differential should be allowed for rate-making purposes and, if not, the amount that should be disallowed. Any such disallowance would not be retroactive, however, but rather any amount disallowed would be applied prospectively as a credit to ECG's revenue requirement for Fiscal 2002.

In determining that it was appropriate to disallow $11.0 million, the Board made use of the notional deferral account, as was contemplated in the settlement proposal. EGDI submissions to the Board on the Motion have not convinced the Board that the $11.0 million disallowance should be reviewed or varied. While EGDI still has the obligation to manage the contracts prudently over the life of the contracts there will be no further disallowance in relation to the prudence of the decision to enter into those contracts.

There is nothing in the Motion to convince the Board that it has made an error that needs to be corrected. Therefore, EGDI has not met the test under Rule 44.01.

The Board's expectations regarding the evidence to be filed by EGDI in relation to its outsourcing arrangements, in the upcoming rates case, RP-2002-0133

EGDI provides a monopoly service and the Legislature has established the Board as a regulator with a mandate to balance the various aspects of the public interest, including the interests of the corporation and the interests of ratepayers. The corporation wants to maximize its returns; the ratepayer wants to minimize rates. In the context of the interests of the corporation, the Business Corporations Act, R.S.O. 1990, c. B. 16, as amended ("OBCA"), provides as follows:

> 115. (1) Subject to any unanimous shareholder agreement, the directors shall manage or supervise the management of the business and affairs of a corporation.
>
> 134. (1) Every director and officer of a corporation in exercising his or her powers and discharging his or her duties shall,
>
> (a) act honestly and in good faith with a view to the best interests of the corporation; and
>
> (b) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.
>
> (2) Every director and officer of a corporation shall comply with this Act, the regulations, articles, by-laws and any unanimous shareholder agreement.

Pursuant to section 36 of the Ontario Energy Board Act ("OEBA"), rates must be "just and reasonable" and the applicant bears the burden of proof. The Board's focus is, and always has been, to ensure that costs are reasonable and prudently incurred before allowing recovery of those costs through rates. In the context of EGDI's outsourcing arrangements, the Board has stated its expectations that EGDI will file evidence that will allow the Board to understand the basis for the cost of the outsourced services. The Board requires this evidence in order to decide whether to allow those costs to be recovered in rates. Ultimately, the burden of proof lies with EGDI. If the Board is not satisfied that the rates applied for are just and reasonable, the Board may fix such other rates as it finds to be just and reasonable.

The Board has not yet commenced the fiscal 2003 rates hearing and has made no findings with respect to what costs may be recovered in rates. All the Board has done is state its expectations with respect to the evidence to be filed in the next rates proceeding. While section 21 (1) of the OEBA gives the Board clear jurisdiction to, "at any time on its own motion and without a hearing give directions or require the preparation of evidence incidental to the exercise of the powers conferred upon the Board by this or any other Act", the Board is of the view that it is not necessary to issue such directions at this time and that it is sufficient for the Board to have clearly stated its expectations, as set out in its Decision.

On this issue, EGDI has not met the test for review under Rule 44.01.

The Motion is dismissed.

DATED at Toronto, February 10, 2003.

Bob Betts
Presiding Member

George Dominy
Member

A. Catherina Spoel
Member