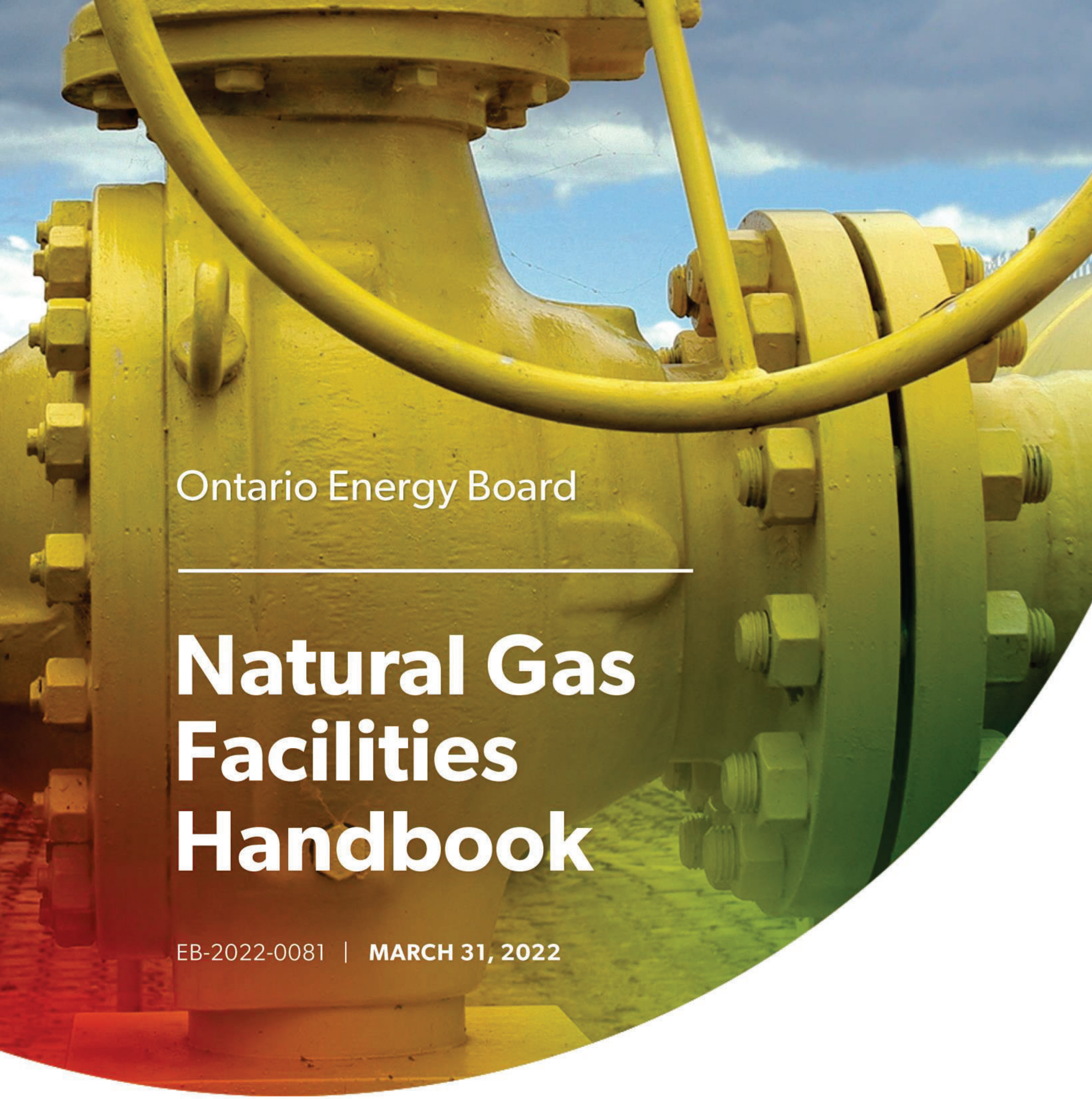
Energy Probe Compendium

EB-2022-0157 EGI Panhandle Regional Expansion Project LTC

Table of Contents

Tab 1

Ontario Energy Board Natural Gas Facilities Handbook (EB-2022-0081), March 31, 2022 (excerpts)



Ontario Energy Board

Natural Gas Facilities Handbook

EB-2022-0081 | **MARCH 31, 2022**

Ontario
Ontario Energy Board

Handbook. Other applicants for LTC are encouraged to use this IRP Framework as a resource to guide their infrastructure planning and consideration of non-pipeline alternatives.

4.4.3 Project Costs and Economics

This section applies only to applicants that are or intend to become rate regulated and seek to include the project costs in a future rates application.

Project Costs

The applicant must provide sufficient information to demonstrate that the estimates of the project costs are reasonable (e.g., a comparison with recent similar projects).

The applicant must adequately identify and describe any risks associated with the proposed project and demonstrate that the proposed contingency budget is appropriate and consistent with the identified risks.

Although project costs are reviewed in detail through the LTC proceeding, the applicant still requires OEB approval to recover those costs in rates that will only apply beginning (at the earliest) in the year in which the in-service date falls. In most cases, the project costs will not be reviewed again in detail in the rates proceeding unless there are material changes relative to the forecast costs of the project that were included in the LTC application.

Project Economics

The applicant must demonstrate that the project's economics meet the OEB's economic tests using the methodology outlined in EBO 188 (including Appendix B) or EBO 134[39], as applicable. Where a contribution in aid of construction is required from a customer to make a project feasible, the applicant must demonstrate that the amount of the contribution is reasonable and consistent with EBO 188, EBO 134 and its own customer connection policies. An applicant may propose to use an Hourly Allocation Factor (HAF) to allocate the capital costs of a project amongst existing and future customers of those facilities for the purpose of calculating the contribution in aid of construction. If so, the applicant must demonstrate that the project is eligible or suitable for it, and that the proposed methodology for calculating the HAF is reasonable.[40]

[39] Also see the Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, EB-2012-0092

[40] For reference, see Enbridge Gas Inc.'s SES / TCS / HAF application, EB-2020-0094

If a community expansion project is not economic based on existing rates, an applicant may request a surcharge (e.g., a system expansion surcharge[41] or temporary connection surcharge[42]).[43]

Economic Tests: EBO 188 and EBO 134

One of the OEB's statutory objectives is to facilitate rational natural gas expansion, and in so doing the OEB ensures that there is no undue cross-subsidization between existing and new customers. Two decisions issued by the OEB, EBO 188 and EBO 134, describe some of the economic thresholds that natural gas expansion plans need to meet to be eligible for cost recovery through OEB approved rates. The EBO 188 economic feasibility test guidelines apply to distribution pipelines, whereas the EBO 134 economic feasibility test guidelines apply to transmission pipelines.

The applicant must file evidence describing in detail how the proposed project meets the economic tests described in EBO 188 or EBO 134, as applicable, to demonstrate that the project does not lead to undue cross-subsidization from existing customers.

EBO 188

By way of summary, the EBO 188 decision describes the economic test that should be used to evaluate a proposed expansion of a natural gas distributor's distribution system. The key principle behind the test is that a distributor's total portfolio of expansion projects should not result in undue cross-subsidization from existing customers over the long term. This analysis is performed using a discounted cash flow analysis to calculate the Profitability Index (PI) of a project: a PI of less than 1.0 indicates that the revenues forecast from a new project are less than the forecast costs, and a PI greater than 1.0 indicates that the forecast revenues of a project are greater than the forecast costs. For individual distribution projects requiring LTC, the OEB typically expects that the PI will be at least 1.0. In cases where a project is below a profitability index (PI) of 1.0, a distributor may ask the new customers to pay an upfront contribution in aid of construction to increase the PI to 1.0 for the project or may apply for a SES.

---

41 An SES is a charge to new customers of a community expansion project to improve the financial feasibility of the project and avoid cross-subsidization by existing customers.

42 A TCS is a charge to new customers of a non-community expansion project to improve the financial feasibility of the project and avoid cross-subsidization by existing customers.

43 Such as with Enbridge Gas Inc.'s SES / TCS / HAF application, EB-2020-0094. Currently only Enbridge Gas Inc. has blanket approval to charge an SES or a TCS. In its decision (issued on November 5, 2020), the OEB approved Enbridge Gas Inc.'s application for blanket approval to charge an SES for community expansion projects serving 50 or more customers and a TCS for small main extension and customer attachment projects serving less than 50 customers.

EBO 134

Like EBO 188, the EBO 134 guidelines direct applicants to use a discounted cash flow method to calculate the PI for the project as a minimum test in assessing the feasibility of transmission projects. The difference between EBO 134 and EBO 188 is the inclusion in EBO 134 of Stage 2 and Stage 3 cost/benefit analyses, and that not all transmission projects will require a PI of at least 1.0. The second stage is intended to quantify other public interest factors not considered at stage one. All other quantifiable public interest information (costs and benefits) should be provided at this stage. The third stage is intended to consider any other relevant unquantifiable costs and benefits in addition to the results from stage one and stage two.

The test in EBO 134 is generally applicable to a project where there will be no distribution customers directly connected to the pipeline.[44]

4.4.4 Environmental Impacts

The OEB will consider any input from the Ontario Pipeline Coordinating Committee (OPCC), which is a committee chaired by a member of OEB staff and comprised of standing representatives of several provincial ministries and agencies.[45] In addition to its standing members, the OPCC may also include representatives of municipalities and other provincial (e.g., Niagara Escarpment Commission) or federal authorities (e.g., National Capital Commission) depending on the location of the project. The OPCC's mandate is to provide for a coordinated process, within the timelines contained in the Environmental Guidelines, to review the environmental report and provide comments on environmental impacts and potential related issues. In accordance with the Environmental Guidelines, prior to filing an application with the OEB an applicant is required to distribute the Environmental Report to OPCC members and seek comments and direction on potential impacts and recommended mitigation measures. The Environmental Report and the record of any feedback provided by members of the OPCC, including any issues and concerns, potential environmental effects and proposed mitigation, are required to be filed in the evidence supporting the application. An applicant is also required to provide a list of all permits and approvals required by OPCC members and any other project specific permits and approvals together with expected acquisition timelines. Applicants are advised to refer to the Environmental Guidelines for more information on the Environmental Report and related environmental filings.

[44] Union Gas Limited, Kingsville Reinforcement Project, EB-2018-0013, Decision and Order, page 4

[45] Updated listing of OPCC members is posted on the OEB website

Tab 2

Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092), February 21, 2013

Ontario

ONTARIO ENERGY BOARD

Filing Guidelines on the Economic Tests for Transmission Pipeline Applications (EB-2012-0092)

February 21, 2013

Ontario Energy Board
Filing Guidelines on the Economic Tests for Transmission Pipeline Applications

The Report of the Board on the Expansion of the Natural Gas System in Ontario, the E.B.O. 134 Report, forms the basis of the filing requirements on the economic feasibility test to be applied to leave to construct applications for pipeline transmission projects.

These requirements apply to all Ontario Energy Board regulated gas utilities requesting approval to construct new transmission facilities. For the purpose of these Guidelines transmission pipelines are defined as any planned or proposed pipeline project that would provide transportation services to move natural gas on behalf of other shippers within Ontario. Distribution system expansion pipelines that are subject to the filing guidelines set in the EBO 188 would not be subject to the proposed filing requirement.

The Board recognizes the difficulties an applicant may encounter in obtaining reliable and accurate information to conduct an assessment as defined in the new filing requirement. However, the Board expects the applicants to employ the best efforts to obtain the necessary information and data. In the Board's view, consultation with other transmitters operating in the Province is an appropriate vehicle for an applicant to use to assess the impact of its proposal on existing pipelines. The results of these consultations should be filed with the Board as part of the application pre-filed evidence.

When it is demonstrated that data for a quantitative assessment is not available, the Board expects that prospective applicants will provide an assessment of qualitative and directional impacts of the proposed pipelines on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability, and access to supplies.

The Board believes that the economic feasibility test outlined in the E.B.O 134 Report continues to form the basis of sound filing requirements for new pipeline transmission projects, and these requirements are incorporated into this filing guideline.

1. The Board finds that of the tests currently in use by the utilities, the Discount Cash Flow ("DCF") analysis provides a superior measure of the subsidy required from existing customers for a particular project.

2. The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion.

3. The Board encourages the use of more formal risk measurement in the feasibility test and it would not discourage the use of sensitivity analyses of variables being regularly employed in the test.

4. The Board finds that incremental costs should be used in evaluating the feasibility of system expansion.

5. The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing.

6. The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest.

7. The first stage is a test based on a DCF analysis.

8. The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage.

9. The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two.

10. A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated.

11. The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project.

12. Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest.

13. The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class.

14. Any project brought before the Board for approval should be supported by an assessment of the potential impacts of the proposed natural gas pipelines on the existing transportation pipeline infrastructure in Ontario, including an assessment of the impacts on Ontario consumers in terms of cost, rates, reliability, and access to supplies.

Tab 3

EB-2022-0157, Exhibit B, Tab 1, Schedule 1, Attachment 2, Pages 1 to 4, Filed 2022-06-10, “Panhandle Regional Expansion Project, In Franchise Binding Reverse Open Season”

September 29, 2021

Panhandle Regional Expansion Project

In Franchise Binding Reverse Open Season

On February 17, 2021, Enbridge Gas Inc. ("**Enbridge Gas**") issued a Panhandle Regional Expansion Project Expression of Interest and Capacity Request ("**EOI**"). Based on the interest received from the EOI, Enbridge Gas expects expansion facilities will be required to meet the incremental demands for gas distribution service. To ensure economically efficient expansion of Enbridge Gas's pipeline system, we are now inviting binding bids for existing capacity turn-back.

Enbridge Gas is offering all existing distribution contract rate customers in the proposed project service area (see attached map on page 3) the opportunity to "turn-back" or de-contract existing distribution capacity.

Bids submitted in this Binding Reverse Open Season represent a legally binding commitment to turn back capacity. Existing customers should submit only one binding bid form for each distribution contract. Enbridge Gas, in its sole discretion, reserves the right to reject any and all bids received.

For details on the proposed Panhandle Regional Expansion Project, please visit: **www.enbridgegas.com/PanhandleRegionalExpansion**

This Binding Reverse Open Season closes, and bid forms are due, no later than **12:00 p.m. EDT Friday October 15, 2021.**

Submitting a Bid Form

If you wish to participate in this Binding Reverse Open Season please complete, sign and return the attached Binding Reverse Open Season Bid Form via email to Economic.Development@enbridge.com**.** Completed forms must be returned by email on or before 12 p.m. EDT on Friday October 15, 2021. The returned Binding Reverse Open Season Bid Forms will be time-stamped by the date on the bidder's email.

This process is designed to assist Enbridge Gas with determining the optimal facility requirements to meet market needs and prepare an application to the Ontario Energy Board for the proposed Panhandle Regional Expansion Project. Enbridge Gas will acknowledge receipt of all Reverse Open Season Bid Forms by email on or before the end of day on Monday October 18, 2021.

Any suggested contractual Condition(s) Precedent that the bidder proposes should be clearly articulated and attached to the Binding Reverse Open Season Bid Form and will be considered during the capacity turnback process.

If you have any questions about this Binding Reverse Open Season or the Panhandle Regional Expansion Project, please contact your account manager or one of the following:

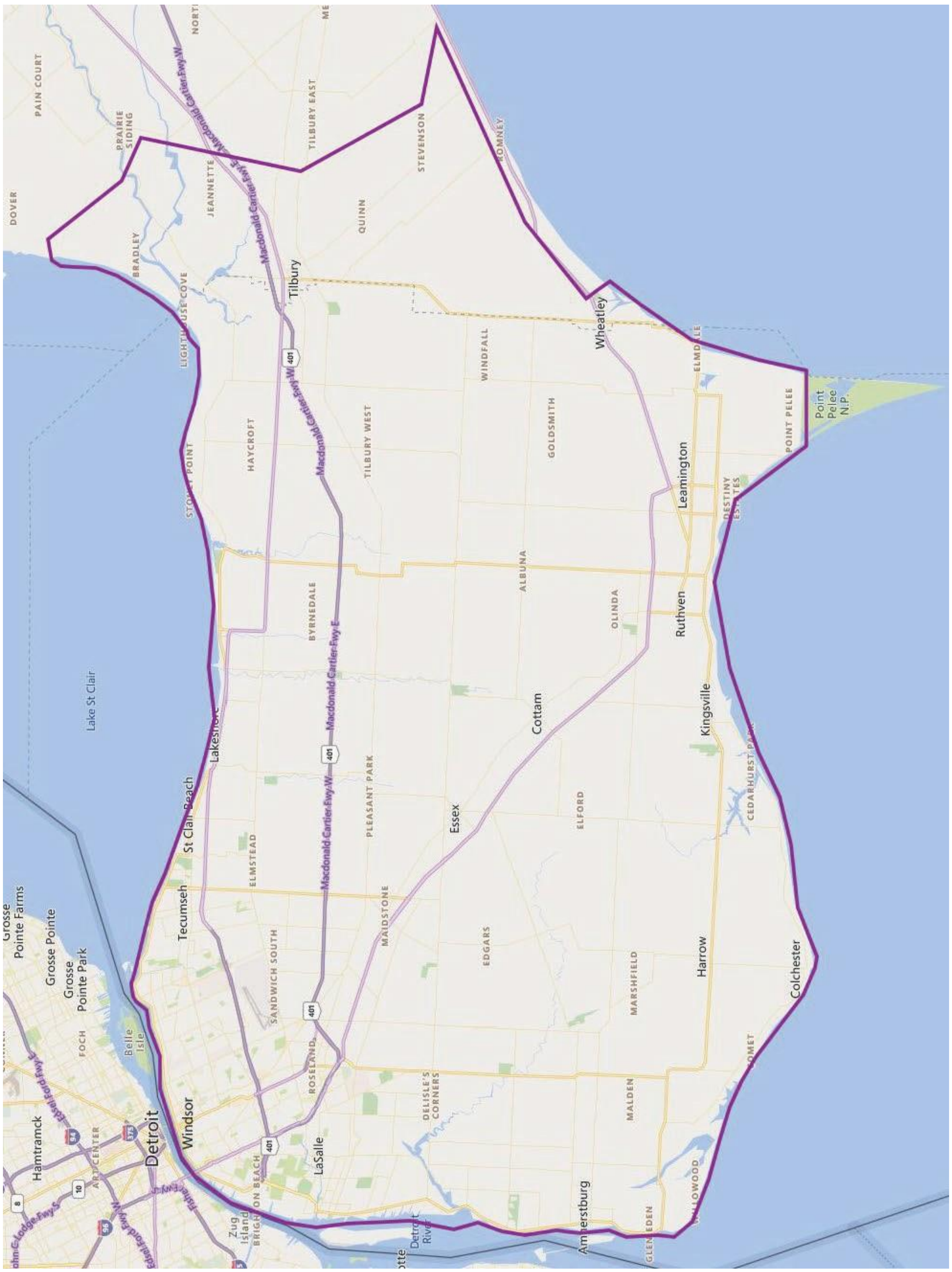
Patrick Boyer
Account Manager
Cell: (519) 436 4915
Patrick.Boyer@enbridge.com

Paul Rikley
Account Manager
Cell: (519) 350 2570
Paul.Rikley@enbridge.com

Mark Noce
Account Manager
Cell: (289) 659 3667
Mark.Noce@enbridge.com

Proposed project service area for Binding Reverse Open Season

The map below outlines the area that is under consideration for a potential project to expand natural gas capacity. All distribution contract rate customers holding existing Firm or Interruptible distribution capacity in this area that wish to turn back some or all of this capacity are invited to participate in this Binding Reverse Open Season.



Binding Reverse Open Season Bid Form:

Please complete, sign and return this Binding Reverse Open Season Bid Form ("**Bid Form**") on or **before 12:00 p.m. EDT on Friday October 15, 2021**, via email to Economic.Development@enbridge.com

It is understood that Enbridge will review all Bid Forms and acknowledge all Bid Forms received on or before October 15, 2021. If Bidder's bid is accepted, with or without conditions, Enbridge will notify Bidder accordingly.

Bidders may only submit one Bid Form per distribution contract. Bid Forms will be treated as confidential and only aggregated or non-identifiable data will be used to support any application to the Ontario Energy Board.

Site address: ____ Distribution Contract SA: ___________
911 address

Binding Reverse Open Season (Turnback of existing capacity under contract at an existing site)

☐ **Turn back existing FIRM distribution service.** The amount of **firm** distribution service at the identified location no longer required by the customer.

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Turnback (m^3/hr)											
Cumulative											

☐ **Turn back existing INTERRUPTIBLE distribution service.** The amount of **interruptible** distribution service at the identified location no longer required by the customer.

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Turnback (m^3/hr)											
Cumulative											

Bidder Conditions Precedent for **turnback of capacity**: If the Bidder's request to turn back excess or unwanted capacity is subject to Conditions Precedent, please include these Conditions Precedent in the space below or attach a separate page to this Bid Form:

Bidder's legal name: ____

Name of Authorized Representative: __________________________ __________________________
Please Print Signature

Phone: __________________________ Email: ____

Dated this ____ day of __________, 2021

Tab 4

Decision and Order, EB-2018-0013, Union Gas Limited, Application for leave to construct a natural gas transmission pipeline and associated facilities in the Town of Lakeshore and the Town of Kingsville in the County of Essex

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

DECISION AND ORDER

EB-2018-0013

UNION GAS LIMITED

Application for leave to construct a natural gas transmission pipeline and associated facilities in the Town of Lakeshore and the Town of Kingsville in the County of Essex

BEFORE: Susan Frank
Presiding Member

Allison Duff
Member

September 20, 2018

1 INTRODUCTION AND SUMMARY

Union Gas Limited (Union) applied to the Ontario Energy Board (OEB) under section 90(1) of the *Ontario Energy Board Act, 1998* (Act) for an order granting leave to construct approximately 19 kilometers of natural gas transmission pipeline in the Town of Lakeshore and the Town of Kingsville in the County of Essex (Kingsville Reinforcement Line or Project). Union proposed an in-service date of November 1, 2019 with construction beginning in the summer of 2019.

A map of the proposed Kingsville Reinforcement Line is in Schedule A.

The OEB approved the Building Owners and Managers Association, Greater Toronto (BOMA), Industrial Gas Users Association (IGUA) and the Ontario Greenhouse Vegetable Growers (OGVG) as intervenors, eligible to apply for cost awards. The OEB approved the City of Kitchener, an embedded gas distributor in Union's south franchise territory, as a late intervenor.

Pursuant to section 90 (1) of the Act, the OEB grants Union leave to construct the Kingsville Reinforcement Line, subject to the Conditions of Approval in Schedule B.

Findings

The OEB finds that Union has demonstrated the need for this Project - a transmission line with broad benefits to the Panhandle Transmission System. The OEB is aware that Union has filed another leave to construct application for the Chatham-Kent area, which relies on the incremental capacity provided by this Project[2].

The Project addresses the forecast load growth in the Kingsville-Leamington area, growth that cannot be accommodated with the existing distribution system. Union identified 14 executed contracts for firm service and an additional 20 contracts under negotiation that were dependent on the in-service date of November 1, 2019.

3.2 Project costs and economic tests

Union estimated a total cost of $105.7 million to construct the Project. While the OEB deferred hearing Union's ICM request for recovery of this cost, a cost-benefit economic evaluation is in scope for this proceeding.

Union applied the OEB's economic test for transmission pipeline applications[3] (E.B.O. 134 test). Union's stage 1 discounted cash flow analysis indicated a profitability index (PI) of 0.44 and a net present value of negative $59.2 million. Given the PI was less than one, Union undertook a stage 2 analysis which considered the estimated energy cost savings as a result of customers using natural gas instead of other fuels to meet their energy requirements. The stage 2 net present value results over 20 years ranged from $283 million to $472 million, depending on the assumptions for the alternative fuel mix.

As the Project addressed both transmission and distribution needs, the OEB questioned Union's use of the E.B.O. 134 test exclusively, with no reference to the OEB's economic test for distribution applications[4] (E.B.O. 188 test). The OEB also asked Union whether it had sought contributions-in-aid of construction, an element of the E.B.O. 188 test.

Union responded that the E.B.O. 188 test for distribution applications did not apply to this application for a transmission line. Union stated that it was not appropriate to apply

---

[2] EB-2018-0188
[3] Economic Test for Transmission Line Applications, E.B.O. 134, dated June 1, 1987, and amended on February 21, 2013 (EB-2012-0092), and referred to as the *Filing Guidelines on the Economic Tests for Transmission Pipeline Applications*
[4] *Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario*, E.B.O. 188, January 20, 1998

the E.B.O. 188 test as the incremental forecast demand extended throughout the Panhandle service area and no distribution customers would be connected directly to the new pipeline.

OEB staff submitted that it was appropriate for Union to apply the E.B.O. 134 test as the Project is defined as a transmission asset and results in a total positive net present value at a stage 2 analysis.

OGVG indicated that the OEB raised the possibility of contributions-in-aid-of construction for the first time in this application process, an issue not associated with transmission investments under the E.B.O. 134 test. OGVG submitted that its members need to know in advance their obligations with respect to the cost of natural gas infrastructure and that those obligations are based on consistent regulatory treatment of similar projects.

IGUA submitted that if the OEB concludes that the Project serves both transmission and distribution functions, a more nuanced approach to economic evaluation and associated cost responsibility requirements might be warranted. IGUA provided an example whereby 10% of the cost was recovered through contributions-in-aid of construction from the 34 customer contracts dependent on capacity enabled by the Project. IGUA submitted that contributions-in-aid of construction would reduce the shortfall in the stage 1 analysis and improve the PI for the Project.

Findings

The OEB finds that Union appropriately followed the OEB's E.B.O. 134 test for transmission projects. While the stage 1 analysis results in a net present value of negative $59.4 million and a P1 of only 0.44 over 40 years, broader economic benefits identified in the stage 2 analysis support the approval of the Project.

While the OEB has approved the Project, there are some concerns that the OEB would like to observe.

First, the new pipeline has ancillary distribution benefits according to Union in addition to the transmission functions. The distribution benefits are evident as Union identified 14 firm customer contracts executed and 20 customer contracts being negotiated which rely on the approval and construction of the Project. The OEB finds that the Project meets both distribution and transmission needs, yet the OEB's economic tests are exclusive, applicable to either distribution or transmission lines.

Second, the economic test for transmission, E.B.O. 134, does not attribute who should pay with each stage of testing. For distribution pipelines, the more recent E.B.O. 188 test recognizes that if there is insufficient new revenue generated by the project to cover its costs, capital contributions are required from the benefiting parties. Under E.B.O. 134, the stage 2 benefiting parties would be downstream connecting customers and the local economy. Currently there is no mechanism to have these parties make a contribution to the costs despite their substantial benefit.

For natural gas in Ontario, no economic test or ratemaking mechanism exists today to allow these discrepancies to be addressed.

The OEB acknowledges the creative thinking included in IGUA's submission. While it is not appropriate to split the costing between transmission and distribution pipelines as proposed by IGUA in this proceeding, such proposals may help inform future thinking on the treatment of dual function pipelines.

3.3 Alternatives

Union considered four alternatives to the Project by evaluating the capital costs, net present values, in-service dates and future facilities requirements from 2024 to 2036. The alternatives explore various sizes of pipe, increased deliveries from Ojibway and distribution options. Union submitted that the Project is the preferred alternative to address the need in both the five-year and longer-term horizon.

In defense of the proposed timing, Union submitted that if the Project were completed by November 1, 2019 additional distribution costs of $10.4 million could be avoided.

No party raised concerns with Union's evaluation of alternatives. OGVG was concerned that if the Project were delayed, then $10.4 million of additional distribution assets would be required.

Findings

The OEB finds that the Project is the preferred alternative. The Project has the highest net present value, addresses incremental demand in the Kingsville-Leamington area in 2019 and is consistent with other, longer-term considerations for the Panhandle Transmission System.

Tab 5

**Decision and Order, EB-2016-0186, Union Gas Limited,
Application for approval to construct a natural gas pipeline
in the Township of Dawn Euphemia, the Township of St. Clair and the
Municipality of Chatham-Kent and approval to recover the costs
of the pipeline., February 23, 2017 (excerpts)**

Ontario

Ontario Energy Board
Commission de l’énergie de l’Ontario

DECISION AND ORDER

EB-2016-0186

UNION GAS LIMITED

Application for approval to construct a natural gas pipeline in the Township of Dawn Euphemia, the Township of St. Clair and the Municipality of Chatham-Kent and approval to recover the costs of the pipeline.

BEFORE: **Allison Duff**
Presiding Member

Cathy Spoel
Member

Paul Pastirik
Member

February 23, 2017

1 INTRODUCTION AND SUMMARY

This is a decision of the Ontario Energy Board (OEB) on an application filed by Union Gas Limited (Union). Union applied under section 90(1) of the *Ontario Energy Board Act, 1998* (the Act) for leave to construct approximately 40 kilometers of 36 inch diameter pipeline from Union's Dawn Compressor Station in the Township of Dawn-Euphemia to its Dover Transmission Station in the Municipality of Chatham-Kent (the Project). A map of the Project is attached as Schedule A.

Union also applied for approval of the recovery of costs associated with the construction of the Project pursuant to section 36 of the Act; approval of a 20-year depreciation term; and approval of an accounting order to establish a Panhandle Reinforcement Deferral Account pursuant to section 36 of the Act.

Union's evidence is that the Project is needed to meet increasing demand for firm service on the Panhandle System in the Leamington-Kingsville area, from greenhouse operations, commercial and small industrial customers and anticipated residential growth.

One of the issues that arose in the proceeding was whether there were alternatives to the Project that did not require the construction of new pipeline facilities. Specifically, the issue is whether Union's customers are best served through the proposed pipeline's capacity or through capacity acquired on a contractual basis from Panhandle Eastern Pipe Line Company (Panhandle Eastern) through the Ojibway international connection point near Windsor. A map showing these interconnections is attached as Schedule B.

The OEB grants leave to construct the Project, subject to the Conditions of Approval, which are attached as Schedule C. For the reasons set out below, the OEB finds that the construction of the Project is in the public interest as it is the most reliable approach to meeting demand in the Leamington-Kingsville area.

3.2 OEB's economic tests

Union's evidence is that the total cost of the Project was $264.5 M. Union assessed the economic feasibility of the Project by applying the OEB's economic tests.[3] Over a 20-year term, the net present value (NPV) for the Stage 1 test was negative $212 M based on the facilities required for five years of demand day growth. With a Stage 1 NPV less than zero, Union conducted a Stage 2 NPV test and estimated energy cost savings to be approximately $805 M, resulting in an NPV greater than zero.

Union compared the NPV of the Project to the NPV of all alternatives considered. Alternative 2 assumed incremental deliveries of 34 TJ/day or total deliveries of 94 TJ/d at Ojibway, plus new facilities. Alternative 2 was presented in Union's evidence as an alternative to the Project. The NPV's changed when Union considered the assets required after five and six years of demand day growth.

Table 2 - Stage 1 NPV of Proposal and Alternative 2 with 20-year term ($ Millions)

Description	NPV – Assets five years	NPV – Assets six years
Project	$(212)	$(239)
Alternative 2	$(207)	$(271)

Union's evidence is that incremental facilities were required for both scenarios to meet the increase in demand. Union stated that there was little difference in the NPVs of these alternatives looking at assets for five years, but the more economic option over the longer term is the Project.

Many intervenors who submitted the OEB should not approve the application did not comment on Union's NPV and economic tests. The submissions of these intervenors focused on the alternatives that Union did not consider and were not included in evidence.

VECC submitted that the cost difference and NPVs of Union's alternatives are a distraction to the important issues raised by the application and obfuscate the analysis. VECC noted that the additional costs of Alternative 2 only come into play in 2022 and are based on the accuracy of Union's forecast of demand.

[3] Filing Guidelines on the Economic Tests for Transmission Pipeline Applications, Feb 21, 2013

LPMA submitted that the Project met the OEB's economic test in Stage 2. Although LPMA did not agree with all the assumptions used to calculate the NPV of the stage 2 benefits, LMPA agreed that the NPV is well in excess of the $212 shortfall in the Stage 1 NPV calculation.

Findings

The OEB finds that the Project meets the OEB's economic tests. The OEB finds that the Stage 2 benefits sufficiently exceed the Stage 1 net cost, and result in a positive NPV.

Union's Stage 1 NPV was negative $212 based on a 5-year forecast and 20-year term. The NPV changed slightly to negative $207 based on a 40-year term. With a 40-year term, the NPV for Alternative 2 changed from negative $207 to negative $201. The OEB finds the Stage 1 NPVs for the Project to be similar to Union's Alternative 2, despite a change in term.

The OEB agrees with LPMA that not all of Union's assumptions in its Stage 2 analysis may be adequately justified, but the OEB finds the $805 M in estimated benefits so large that even with some adjustments the benefits will exceed the net cost estimate in Stage 1.

Based on Union's forecast five-year demand, the OEB finds that Union has demonstrated that the economic tests required by the OEB's filing guidelines have been met.

3.3 Potential rate impacts to customers

Based on Union's proposed costs and rate recovery, the average total bill impact for Union South customers ranged from 1.2% for residential rate M1 to 5.8% for small rate M4[4].

Union's cost estimate included depreciation expense based on a 20-year depreciation period, which is shorter than the 50 years in the OEB's approved depreciation rates for these assets. The depreciation expense to be recovered from customers would be lower by $3.5 M in 2017 and $7.4 M in 2018 if depreciated over 50 years.[5]

Union submitted that a shorter amortization period was warranted given the uncertainties with Ontario's Cap and Trade program and the introduction of the government's Climate Change Action Plan (CCAP). Union submitted that these new

---

[4] Exhibit A, Tab 8, Schedule 6, p.2
[5] Exhibit J1.3

initiatives add significant risk to the return of any capital invested in natural gas infrastructure over the medium to long term. Union submitted that a 20-year period better aligns the recovery of the asset costs with the timing of government restrictions and potential elimination of natural gas heating of homes and businesses.

All but one of the intervenors disagreed with Union's proposal for a 20-year amortization period. They noted that the settlement agreement entered into at Union's most recent cost of service proceeding refers to OEB-approved 2013 depreciation rates. These intervenors argued that the terms of the settlement proposal prohibit the use of different depreciation rates, and that depreciation was not identified as a Y-factor in the settlement proposal. These intervenors also argued that if a change was to be considered by the OEB it should be during a rebasing year, not during the IRM term, based on a comprehensive review of all assets.

LPMA supported Union's proposal, submitting that a 20-year period reduced the risk for Union resulting from Cap and Trade and CCAP, and reduced the total net present cost to customers.

Union proposed two changes to the cost allocation methodology approved by the OEB when rates were established in 2013. The proposed cost allocation would determine how the Project costs would be recovered until 2019, the end of Union's current IRM term.

First, Union proposed to base the allocation on the Panhandle System's design day demand plus incremental design day demands of the Project. In 2013, the OEB had approved a cost allocation methodology based on design day demands from the combined Panhandle and St. Clair Systems.

Second, Union proposed to exclude ex-franchise Rate C1 and M16 firm contracted demands from the cost allocation. In 2013, the OEB had approved a cost allocation methodology that included in-franchise and ex-franchise rate classes.

Union's position is that using the combined Panhandle and St. Clair Systems to allocate costs no longer reflects the costs to serve customers on their respective parts of these Systems. In addition, Union submitted that C1 and M16 ex-franchise customers are not driving the need for the Project because their gas flows counter to the flow of design day volumes. Union's proposed allocation would result in a re-allocation of 15% of the Project costs to in-franchise customers, rather than allocating them to C1 and M16 customers. A full comparison of the current OEB-approved and the proposed allocation follows.[6]

Line No.	Rate Class	Design Day Demands St. Clair System (%) (a)	Design Day Demands Panhandle System (%) (b)	Project Cost Allocation Factors OEB-Approved Allocation (%) (c)	Project Cost Allocation Factors Proposed Allocation (%) (d)
1	Rate M1	7%	40%	21%	40%
2	Rate M2	2%	14%	7%	14%
3	Rate M4	0%	14%	7%	14%
4	Rate M5	-	0%	0%	0%
5	Rate M7	-	4%	2%	4%
6	Rate T1	9%	5%	6%	5%
7	Rate T2	82%	23%	42%	23%
8	Total In-franchise	100%	100%	85%	100%
9	Rate C1	-	-	13%	-
10	Rate M16	-	-	3%	-
11	Total Ex-franchise	0%	0%	5%	0%
12	Total	100%	100%	100%	100%

All Intervenors except two disagreed with Union's proposal to change the cost allocation methodology for the Project. These intervenors submitted that a change to cost allocation should only be considered in a rebasing year, not during an IRM term, as changes to one part of cost allocation affect all other customers. LPMA, VECC and OEB staff indicated that they were not opposed to Union's proposal, but suggested further review of the impacts are required.

APPrO and IGUA supported Union, arguing that Union's cost allocation proposals were in line with the principle of cost causality and consistent with how the Panhandle System is used.

Findings

The OEB will not approve Union's proposals for a 20-year depreciation period and a revised cost allocation methodology. The OEB finds that both proposals should be deferred to Union's next cost of service or custom IR application. It would be inconsistent to change the depreciation term and cost recovery for one project, while Union's other assets are depreciated and recovered on different bases. A comprehensive review is required for parties to test, and the OEB to assess, the merits

[6] Exhibit J1.2 Attachment 2, page 3

and implications of these two proposals and this should be at Union's next cost of service or custom IR application.

While these proposals may have merit, they cannot be adequately considered during the IRM term, for one project in isolation. A leave-to-construct application requesting a capital pass-through mechanism for cost recovery over 14 months is not the appropriate forum to consider deviations from principles embedded in current OEB-approved rates.

A proper review of these issues will need to include the full range of possible amortization periods, and the impacts on all customer classes of a change to the cost allocation methodology

Given these findings, it is not necessary for the OEB to comment on whether Union's proposal is consistent with the settlement agreement.

3.4 Facilities and non-facilities alternatives to the Project

Exhibit A, Tab 6 of Union's evidence describes the alternatives to the Project that were considered by Union. Union defined an acceptable alternative as one which allows Union to maintain minimum inlet pressures on a design day and meet design day requirements to supply its downstream distribution systems. The alternatives considered by Union are intended to serve the five-year forecasted demand growth from 565 TJ/d to 671TJ/d by 2021, and further consideration for expected future growth beyond 2021.

Union's Alternative 1

This alternative involves construction of a new 30 or 36 inch pipeline from Dawn alongside the existing Panhandle pipeline which would continue to be used.

Union forecast the cost of this alternative at an NPV of negative $224 M which is $12M more expensive than the Project's estimate of negative $212 M. The Project also has the advantage of eliminating the need for additional land and easements and ongoing maintenance costs to preserve the integrity of the existing pipeline.

Union's Alternative 2

This alternative involves contracting for an additional 34 TJ/d of gas supply at Ojibway and installing incremental pipeline and station facilities along the Panhandle System to serve the remainder of the demand from Dawn.

Union's forecast of the NPV for this alternative was negative $207 M. When comparing this to the Project's NPV of negative $212 M, Union did not consider this small differential to be worth the added risk of this alternative. Union's evidence is that

Tab 6

EBO 188, Final Report of the Board, a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc., January 30, 1998

Rep: OEB

Doc: 12JLZ

Rev: 0

Was preliminary page 1 1
E.B.O. 188

IN THE MATTER OF the *Ontario Energy Board Act*[12JF7-0:1], R.S.O. 1990, c. O.13; 2

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to natural gas system expansion for The Consumers' Gas Company Ltd., Union Gas Limited and Centra Gas Ontario Inc. 3

BEFORE: G.A. Dominy 4
Presiding Member
R.M.R. Higgin
Member
J.B. Simon
Member

FINAL REPORT OF THE BOARD 5

January 30, 1998 6

Was preliminary page 2 7

Blank page

Was page i 8

TABLE OF CONTENTS

9

APPENDICES 10

11

Was page ii 12

Blank page

1. THE PROCEEDING Was page 1 13

1.1 THE BACKGROUND 14

1.1.1 In a Notice of Public Hearing dated July 31, 1995, the Ontario Energy Board ("the Board") made provision to hold a public hearing under subsection 13(5) of the *Ontario Energy Board Act* ("the OEB Act", "the Act") to inquire into, hear and determine certain matters relating to the expansion of the natural gas systems of The Consumers' Gas Company Ltd. ("Consumers Gas"), Union Gas Limited ("Union") and Centra Gas Ontario Inc. ("Centra"), (collectively "the utilities"). The proceeding was given Board File No. E.B.O. 188. 15

1.1.2 In Procedural Order No. 1 the Board ordered the utilities to file their current policies for determining the feasibility of proposed system expansions and the application of environmental study reports. 16

1.1.3 The Board held an Issues Day meeting on September 11, 1995 and heard submissions on a proposed Issues List. The Board finalized the Issues List in Procedural Order No. 2 dated September 14, 1995. 17

1.1.4 Procedural Order No. 3, dated October 27, 1995, made provision for parties to file evidence and interrogatories on the evidence. The Order also provided for an alternative dispute resolution ("ADR") conference to be held commencing December 11, 1995 (" the first ADR Conference"). 18

1.1.5 The Board received the *Report to The Ontario Energy Board on The Alternative Dispute Resolution Conference in E.B.O. 188 A Generic Hearing on Natural Gas System Expansion in Ontario*, on December 21, 1995 ("the first ADR Report"). There were divergent views expressed in the first ADR Report by the parties with respect to the principles involved in system expansion. Was page 2 19

1.1.6 Having reviewed the first ADR Report, the Board issued Procedural Order No. 4 on January 11, 1996. In that Order, the Board directed that the parties choosing to file argument and reply should focus their submissions on the following issues: 20

1.1 *Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:* 21

(1) *an obligation to serve in areas where existing service is available;*

(2) *externalities;*

If externalities are to be included, what specific externalities, i.e. economic, social, environmental, should be considered? What tests should be applied and in what sequence?

1.2 *Given the answer to 1.1, what level of financial subsidy, if any, should be applied to system expansion;*

1.3 *Should a portfolio of projects be utilized or should the utilities account for expansion on a project-by-project basis? How should the portfolio be defined?*

1.1.7 Submissions were filed on February 2, 1996 and reply submissions were filed on February 19, 1996. 22

1.1.8 An Interim Report[12JM1-0:1] of the Board ("Interim Report") was issued on August 15, 1996. In that Interim Report the Board made a determination of the issues and set out the principles that would apply to system expansion projects. The Board directed the parties to develop guidelines and policies reflecting the Board's conclusions. The Board also determined that the continuation of the proceeding should be by way of written submissions and a further ADR Settlement Conference ("the second ADR Settlement Conference"). 23

Was page 3

1.1.9 A written common submission was filed by the utilities on September 30, 1996, and submissions and comments on the utilities' common submission were received from Board Staff, Consumers' Association of Canada, Canadian Industry Program for Energy Conservation, Industrial Gas Users Association/City of Kitchener, Green Energy Coalition, Northwestern Ontario Municipal Association/Federation of Northern Ontario Municipalities, Pollution Probe and Ontario Federation of Agriculture/Ontario Pipeline Landowners' Association. 24

1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of: 25

- an ADR Agreement filed with the Board on March 14, 1997, subscribed to by the utilities and supported by a number of other parties ("ADR Agreement"), which included proposed System Expansion Guidelines; 26
- a dissent in the form of a document entitled "Deficiencies of the E.B.O. 188 ADR Agreement and their Rectification" dated April 1, 1997 ("Dissent Document"); 27
- letters of comment from various parties on the ADR Agreement and Dissent Document; and 28
- responses (dated July 25, 1997) to a set of Board clarification questions to the utilities. 29

1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A[241]. 30

1.1.12 In preparing this Final Report, the Board has considered the above documents. The resulting *Guidelines for Assessing and Reporting on Natural Gas Distribution System Expansion in Ontario (1998)* ("the Guidelines") are issued as Appendix B[247] to this Report. 31

1.1.13 The following chapters set out the issues and the principles established in the Interim Report by quoting directly from that document. The positions of the parties are outlined by referencing the ADR Agreement, the Dissent Document and the various comments and clarifications made. 32

1.1.14 The Board's comments and findings are structured as: Was page 4 33

- The Portfolio Approach 34
- Common Methods for Financial Feasibility Analysis 35
- Customer Connection and Contribution Policies 36
- Environmental Planning Requirements for System Expansion 37
- Monitoring and Reporting Requirements 38

1.1.15 As of January 1, 1998, Union and Centra merged into a single company, Union Gas Limited. The Board's findings in this Report and in the Guidelines are applicable to the new company and to Consumers Gas. 39

1.2 INTERVENTIONS 40

1.2.1 The following parties intervened in the proceeding: 41

- Canadian Association of Energy Service Companies 42
- City of Kitchener 43
- Consumers' Association of Canada 44
- Energy Probe 45
- Federation of Northern Ontario Municipalities 46
- Green Energy Coalition 47

- Grenville-Wood 48
- The Heating, Ventilation, Air Conditioning Contractors Coalition Inc. 49
- Industrial Gas Users Association 50
- Municipal Electric Association 51
- Natural Resource Gas Limited 52
- Northwestern Ontario Municipal Association 53
- Ontario Coalition Against Poverty 54
- Ontario Federation of Agriculture 55
- Ontario Hydro 56
- Ontario Native Alliance 57
- Ontario Pipeline Landowners' Association 58
- Ottawa-Carleton Gas Purchase Consortium 59
- Pollution Probe 60
- Power Workers' Union 61
- TransAlta Energy Corporation 62
- TransCanada PipeLines Limited 63
- Woodland Hills Community Inc. Was page 5 64

LATE INTERVENTIONS 65

- The British Columbia Ministry of Energy, Mines and Petroleum Resources 66

2. THE PORTFOLIO APPROACH Was page 7 72

2.1 INTERIM REPORT CONCLUSIONS 73

2.1.1 *The Board believes that utilities are in the best position to plan their distribution systems and, therefore, they should have flexibility in choosing the optimal system design for their distribution system expansions. The Board also believes that if the utilities are allowed to assess the financial viability of all potential customers as a group [using a portfolio approach] more marginal customers could be served as a result of assessing the cost of serving them together with more financially viable customers.* 74

2.1.2 *The Board is of the view that all distribution system expansion projects should be included in a utility's portfolio. This includes projects being developed for security of supply and system reinforcement reasons. The Board will be prepared on an exception basis to consider a utility's submissions as to why a proposed project should not be included in the portfolio but treated separately.* 75

2.1.3 *The Board believes that the issue of the timing of projects can be mitigated by the use of a rolling P.I. [Profitability Index] or benefit to cost ratio in the portfolio. The Board finds that using a rolling P.I. such as the approach used by Union will allow more opportunity for new projects to be added to the portfolio in a more timely fashion and that this is in the public interest. Union's rolling P.I. is a weighted average calculation of the cumulative net present value ("NPV") inflows divided by the cumulative NPV outflows during the preceding 12 months.* 76

2.1.4 *The Board expects the utilities to develop common policies on calculating rolling P.I.s. The forecast rolling P.I.s at a given point in time will be compared to the actuals in each utility's rates case to determine if any action needs to be taken with regard to forecast variances.* 77

2.1.5 *The Board recognizes that subsidization can be measured at both the project and portfolio level. An overall rolling portfolio P.I. of 1.0 means that existing customers will not suffer a rate increase over the long term as a result of distribution system expansion. The Board is therefore of the view that an overall portfolio P.I. of 1.0 or* <u>*better*</u> *(emphasis added) is in the public interest. Using this approach will obviate the need for the intense scrutiny of the financial viability of each project; will ensure that existing ratepayers are not negatively impacted by new projects (given the Board's proviso above on the sharing of risks); and assist communities to obtain gas service where otherwise it would not be financially feasible on a stand-alone basis.* Was page 8 78

2.1.6 *However, at the present time the utilities calculate the DCF ["discounted cash flow"] for proposed projects over long periods of time. The P.I. or benefit to cost ratio is based on this calculation. In the early years, the costs shown in the calculation generally exceed the revenues and there is a greater impact on rates than in the later years when revenues generally exceed costs. The Board is concerned that even if a utility demonstrates that its portfolio of distribution system projects shows a P.I. of at least 1.0 the impact on rates in a given year may be undue. For this reason, the* 79

Board expects the utilities to demonstrate in their rates cases that the short-term rate impact of the cumulative effect of the portfolios will not cause an undue burden on existing ratepayers.

2.1.7 *The Board has considered whether or not it should impose a minimum threshold P.I. for projects* 80
to be included in the portfolios. The Board is concerned that the utilities may proceed with a number of projects with low P.I.s even though the P.I.s of the portfolios remain at 1.0 or greater. The cumulative impact of these projects may result in economic inefficiencies that outweigh the public benefit of the portfolio approach. From time to time, the Board will review the project specific data to monitor the operation of the portfolios in order to determine whether the cumulative economic inefficiency of proceeding with financially unfeasible projects outweighs the public interest in using the portfolio approach.

2.2 POSITIONS OF THE PARTIES 81

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and 82
new facilities to serve them, for a particular test year into one portfolio (the "Investment Portfolio"). The Investment Portfolio would be designed to achieve a NPV of zero or greater (including normalized reinforcement costs).

Was page 9 83
2.2.2 The ADR Agreement proposed that each utility also maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio"). The cumulative result of project-specific discounted cash flow ("DCF") analyses from the past 12 months would be calculated monthly. The costs and revenues associated with serving customers on existing mains would not be included. The Rolling Project Portfolio would be used as a management tool by the utilities to decide on appropriate distribution capital expenditures.

2.2.3 The Dissent Document listed three concerns with the Investment Portfolio proposed in the ADR Agreement: 84

i. service lines off existing mains are included; 85

ii. security of supply projects are not included; and 86

iii. reinforcement costs have been normalized rather than using forecast actual costs. 87

2.3 BOARD'S COMMENTS AND FINDINGS 88

Investment Portfolio 89

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, 90
the Investment Portfolio, all proposed new distribution customer attachments and facilities for a

particular test year. The Investment Portfolio would be designed to achieve a positive NPV (greater than zero) in the test year (including normalized reinforcement costs).

2.3.2 The Board considers that a primary purpose of the Investment Portfolio analysis is to provide the Board with sufficient evidence to decide whether a utility's test year system expansion plan will result in undue rate impacts. 91

2.3.3 The Board understands that the ADR Agreement's proposed Investment Portfolio contains the capital costs of facilities for all new customers added during a test year. The analysis of system expansion financial feasibility includes revenues and operation and maintenance ("O&M") costs associated with these new customers over horizons as proposed up to 40 years. The utilities propose to include an allowance for reinforcement costs to supply the new projects on a normalized basis. 92

Was page 10

2.3.4 Since the Investment Portfolio analysis is intended to predict the financial and rate impacts of test year incremental system expansion capital expenditures and associated revenues and expenses, it is inappropriate to include historic capital expenditures or revenues from attachments in prior periods. 93

2.3.5 The Board accepts the difficulty in isolating test year customers attaching to new mains only (versus those attaching to mains built in prior years). However, as specified in the Guidelines attached as Appendix B, an estimate of the NPV without attachments to prior expansions will be required. This will enable the Board to better monitor the overall economic feasibility of such projects. 94

2.3.6 The Board's interpretation of the Investment Portfolio analysis and its associated rate impacts was assisted by reference to Consumers Gas' interrogatory response [Exhibit I, Tab 7, Schedule 8] in the E.B.R.O. 495 Consumers Gas 1998 rates case. The Board directs the utilities to file future impact analyses in a similar form (see paragraph 6.3.4[214]). 95

2.3.7 The Board sought further explanation for the proposed treatment of reinforcement costs in the Investment Portfolio in its letter of July 4, 1997 to the utilities. The utilities responded that "normalized" reinforcement costs were categorized into "special" reinforcement and "normal" reinforcement. The costs of the former are those associated with specific major reinforcements of the system and are amortized over a period of 10-20 years. The normal reinforcement costs are the residual of the total identified reinforcement costs after the special reinforcement costs are deducted. The historical average for the special and normal reinforcement costs will then be used as the normalized amount to be included in the portfolio analysis as a percentage of the total capital expenditure in the year. 96

Was page 11

2.3.8 The Board finds the proposed treatment of reinforcement costs to be included in the Investment Portfolio as proposed in the ADR Agreement appropriate for overall portfolio analysis purposes. Union currently includes an allowance related to the carrying costs for advancement of reinforcement expenditures resulting from a new project and the Board finds this approach to be appropriate. 97

2.3.9 The Board does not agree that a design target of zero NPV and a P.I. of 1.0 is appropriate given the forecast risks inherent in the Investment Portfolio analysis. As the Investment Portfolio NPV 98 approaches zero the marginal projects will be those with long cash flow break-even periods. Such projects require subsidy for long periods and hence increase short term rate impacts disproportionately.

2.3.10 In addition, the Board notes that the Investment Portfolio includes the costs and revenues associated with attaching customers to existing mains (i.e. mains constructed prior to any given test year). These projects by their nature will be more profitable for the utilities, since the costs of the mains are not included in the Investment Portfolio calculation. The Board concludes that the Investment Portfolio should be designed to achieve a positive NPV including a safety margin (for example, corresponding to a P.I. of 1.10). The Board believes that a portfolio designed in this way will minimize the forecast risks and hence more likely achieve the desired results of no undue rate impacts. 99

Rolling Project Portfolio 100

2.3.11 The Board also accepts the ADR Agreement proposal to maintain a Rolling Project Portfolio. The Rolling Project Portfolio provides an ongoing method of determining the financial feasibility and rate impact of expansion projects over a previous 12 month period. The Rolling Project Portfolio excludes the costs and revenues associated with new customers attaching to mains built prior to the last 12 month period. The Rolling Project Portfolio also provides a basis to compare a utility's Investment Portfolio with actual system expansion. Union has used a Rolling Project Portfolio approach for some time and has filed rate impacts from significant individual projects in its rates cases (e.g. E.B.R.O. 493/494 Exhibit B1, Tab 4, Appendices C and D). 101

2.3.12 As noted above the Board finds the proposed treatment for reinforcement costs to be included in the Rolling Project Portfolio to be appropriate. Was page 12 102

2.3.13 The Board finds the Rolling Project Portfolio as proposed by the utilities to be a useful management tool. This Portfolio provides a mechanism for facilitating review of the financial status of overall distribution system expansion at the time that individual major projects are before the Board for either franchise and certificate approval, or for approval of leave to construct and also for monitoring purposes. 103

2.3.14 The Board has previously expressed its position that inclusion in the Investment Portfolio, of revenues and costs for infill customers connecting to existing mains may provide a mismatch between periodic costs and revenue. The Board notes that the Rolling Project Portfolio, which is the utilities' primary management tool, does not include such infill customers. Therefore, the Board finds that the Rolling Project Portfolio does provide appropriate matching and that an NPV of zero (or greater) is appropriate. 104

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS Was page 13 105

3.1 INTERIM REPORT CONCLUSIONS 106

3.1.1 *The Board believes that a further review of the methodology to be used by the utilities in assessing the project and portfolio financial feasibility is necessary. Among the factors to be considered are the period for new attachments and the time period over which the DCF analysis is calculated. The Board expects utilities to develop common methods for the Stage I Financial Feasibility test that will be used to show whether or not each utility's portfolio of distribution system expansion projects is profitable.* 107

3.2 POSITIONS OF THE PARTIES 108

3.2.1 The ADR Agreement set the following parameters for the DCF analysis: 109

(a) Customer Attachment Horizon 110

A maximum 10 year forecast horizon will be utilized. For customer attachment periods of greater than 10 years an explanation of the extension of the period will be provided to the Board. 111

(b) Customer Revenue Horizon 112

The maximum customer revenue horizon shall be 40 years from the in-service date of the initial mains, except for large volume customers where the maximum shall be 20 years from the customers' initial service. 113

(c) Discount Rate Was page 14 114

The Utilities' incremental after-tax cost of capital will be used for the discount rate. This will be based on the prospective capital mix, debt and preference share costs, and the latest Board approved equity return levels. 115

(d) Discounting 116

Discounting will reflect the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended 117 throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures 118

The incremental costs directly associated with the attachment of new customers to the system will be included in the operating and maintenance expenditures. 119

(f) Gas Costs 120

In the near term, the weighted average cost of gas ("WACOG") will continue to be the proxy for gas costs (gas costs shall be WACOG less the commodity portion of the gas costs). This approach may not be appropriate in the case of projects for large customers, where a specific gas cost forecast may be required. 121

3.2.2 The parties to the Dissent Document submitted the ADR Agreement was deficient in that the utilities had not agreed on a common method for calculating their P.I.s; that a 40 year revenue horizon may result in existing customers paying undue rate increases; and that 40 years is inappropriate in the absence of shareholder responsibility for forecast variations. 122

3.2.3 The Dissent Document also stated that the utilities were understating the costs in the financial feasibility analysis, since they are not using incremental costs for gas storage and transportation services, but have proposed that gas costs be WACOG less the commodity portion of gas costs. 123

3.2.4 The Dissent Document proposed: Was page 15 124

- a customer attachment horizon no longer than 5 years (unless there is a specific contract); 125
- a maximum time period for the DCF calculation of 20 years from the in-service date of the initial main for large volume customers and between 20 and 30 years for small volume customers; 126
- customer use volumes representing the best estimates of the gas consumption for new customers; and 127
- the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission. 128

3.3 BOARD'S COMMENTS AND FINDINGS 129

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the 130
development of the elements of the financial feasibility test. These elements include: customer attachment horizon, customer revenue horizon, discount rate and timing, operating and maintenance expenditures, and weighted average gas costs.

3.3.2 The Board notes that the proposed customer attachment forecast horizon of 10 years is a maximum 131
and adopts this as part of the Guidelines in Appendix B[247].

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of 132
projects with very long cash flow break-even periods and hence high levels of subsidy in the early years. The Board has addressed this issue as part of the design targets for the Investment Portfolio.

3.3.4 The Board concludes that, although theoretically correct, the inclusion of forecast incremental 133
costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.

Was page 16 134

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess short term rate impacts at the Portfolio level. This would be similar to the Rate Impact Measure ("RIM") Test used to evaluate Demand Side Management ("DSM") programs, with the objective of allowing comparisons from year to year and, to a degree, among the separate portfolios of the utilities.

3.3.6 The Board accepts that the DCF calculation will be based on a set of common elements as pro- 135
posed in the ADR Agreement. These common elements will be reflected in the DCF analysis for the Investment Portfolio and the Rolling Project Portfolio filed by each of the utilities in its rates cases, the details of which are set out in Appendix B[247].

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES Was page 17 136

4.1 INTERIM REPORT CONCLUSIONS 137

4.1.1 *In the last few years, the Board has approved contributions in aid of construction in the form of periodic contribution charges for residential and small commercial customers in order to improve the profitability of projects when the P.I. or benefit to cost ratio is less than 1.0.* 138

4.1.2 *The Board notes that accidents of timing and geography can ... lead to inequitable situations where some ratepayers in similar situations may not have to pay a contribution while others are required to pay contributions.* 139

4.1.3 *The Board realizes that customers have indicated their willingness to contribute towards the cost of projects that are not financially feasible in order to obtain gas service. The Board also notes that there may be communities that would be so costly to serve and the P.I. so low that they are unlikely ever to be included in the portfolio. The Board accepts that in these special circumstances a contribution in aid of construction from a community would be acceptable on a case by case basis, but the Board will not expect the utilities to require contributions from all projects which do not meet a threshold P.I. of 1.0. In light of these considerations, the Board expects the utilities to prepare common guidelines on the treatment of customers currently paying periodic contribution charges.* 140

4.1.4 *The Board will review in the next phase of this proceeding the utilities' policies on requiring contributions in aid of construction where dedicated facilities are being constructed primarily for a single customer. In this regard the Board is interested in a policy that deals with all customer classes and expects the utilities to prepare a policy that is common among the utilities.* 141

4.2 POSITIONS OF THE PARTIES Was page 18 142

4.2.1 The ADR Agreement states that the utilities will accept contributions in aid of construction for communities or projects that would otherwise not likely be included in the portfolio. 143

4.2.2 The ADR Agreement also proposed that existing contractual arrangements for the collection of contributions continue with the exception of Consumers Gas' projects for which contributions would be adjusted to achieve a P.I. of 0.8. 144

4.2.3 The ADR Agreement did not propose a definition to be used in determining when a facility is to be considered "dedicated". 145

4.2.4 The Dissent Document does not address the issue of customer contribution policies. 146

4.3 BOARD'S COMMENTS AND FINDINGS 147

4.3.1 The Board notes that the utilities wish to retain the ability to accept contributions in aid of construction for communities or projects that would not otherwise be included in the portfolio. However, no cost limits or P.I. thresholds have been recommended by the parties to assist the utilities in making such decisions. As stated in the Interim Report, the Board believes that the utilities should continue to make decisions on contributions in an even handed manner. 148

4.3.2 The Board recognizes that Union and Centra have been applying a P.I. threshold of 0.8 for the collection of customer contributions for new community attachments. The Board also notes that the utilities proposed this level as the basis for determining the treatment of customers currently paying periodic contributions. In order to ensure fairness and equity in the application and design of contribution requirements, the Board finds that all projects must achieve a minimum threshold P.I. of 0.8 for inclusion in a utility's Rolling Project Portfolio. 149

Was page 19 150

4.3.3 The Board directs the utilities to prepare and maintain a common set of Board-approved customer connection policies that shall, as a minimum, include:

i. the circumstances under which customers will be required to pay for all, or part, of their service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges; and 151

ii. the circumstances where the use of a proposed facility will be dominated by one or more large volume customers for which the utilities will retain the option of collecting contributions in aid of construction. The contribution amounts will be consistent with the cost allocation for such mains and accordingly based on the peak day demand and the cost allocators used by each of the utilities. 152

4.3.4 The Board agrees with the parties that the common criteria for contributions in aid of construction should apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction is expected to take into account the future load growth potential and timing of any such expansion. 153

4.3.5 The Board expects the utilities to bring forward common proposals for customer connection and contribution policies for Board approval. These proposals will be reviewed in each of the utilities' rate cases. 154

Was page 20 155

Blank page

Was page 21 156

5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION

157

5.1 INTERIM REPORT CONCLUSIONS

158

5.1.1 *The Board requires that for all distribution projects, the utilities prepare a display of alternatives (routes and sites) which would show the various trade-offs between customer attachments and environmental, social and financial costs. The Board expects the utilities to prepare common guidelines on how to conduct and document the evaluation of their route selection and to apply these to all expansion projects.*

159

5.1.2 *The Board also expects the utilities to appropriately apply the [Board's] Environmental Guidelines for Locating, Constructing and Operating Hydrocarbon Pipelines in the Province of Ontario, Fourth Edition, 1995[12JF6-0:1] ("the Environmental Guidelines") to all distribution system projects whether or not they involve a facilities application to the Board. The Board believes that the type and level of detail of the environmental investigations conducted by the utilities should be determined on the basis of environmental significance, and not on whether or not a particular application comes before the Board, whether a proposed pipeline is a distribution or transmission line, or whether or not the line will be located in a town. The utilities should conduct and document the necessary investigation and develop mitigation measures where significant environmental features are encountered. It is expected that the utilities will not require additional resources to undertake these investigations.*

160

5.1.3 *The utilities will have to confirm in their rates cases that all proposed projects meet the guidelines on route selection and the Environmental Guidelines and if not, why not. In addition, for facilities applications, the Board expects the utilities to file the project specific route selection display and environmental report. The Board expects that the utilities may incorporate the route selection evaluation into their environmental report.*

Was page 22 161

5.1.4 *The requirements to conduct and document the evaluation of the route selection and to apply the Environmental Guidelines to all distribution projects will be incorporated in the Environmental Guidelines.*

162

5.1.5 *In facilities applications the utilities will also have to continue to satisfy the Board on the design and construction practices and costs for the project. In addition, the Board will have to be satisfied that landowner concerns have been met and that any necessary permits have been obtained.*

163

5.2 POSITIONS OF THE PARTIES

164

5.2.1 The ADR Agreement proposed that whenever a need for gas is identified, and a reasonable source is available, an evaluation would be done on whether this need could be accommodated. Full information on service alternatives would be gathered, including potential customers served, the running line location, construction costs and environmental and socio-economic concerns.

5.2.2 In selecting a preferred route, the ADR Agreement stated that standard environmental guidelines 165
will be used for dealing with most environmental features. Significant environmental features (those not covered by the utilities' standard environmental guidelines) will require separate evaluation and may require public meetings and agency consultation.

5.2.3 The ADR Agreement proposed that costs of avoiding significant environmental features or miti- 166
gating significant environmental impacts will be included in the cost and benefit analysis for the project. For projects with similar economic benefits, routes that avoid significant environmental features will be preferred. Generally, routes with the greatest economic benefits overall will be preferred, subject to the environmental considerations described above.

5.2.4 The parties to the Dissent Document submitted that the ADR Agreement is not consistent with the 167
Board's Interim Report because:

i. the utilities have not yet developed common guidelines on how to conduct and document Was page 23 168
the evaluation of their route selection; and

ii. according to the ADR Agreement, the utilities can select a route that will cause significant 169
harm to the local environment if the route's economic benefits exceed its costs to the environment.

5.2.5 The parties to the Dissent Document proposed that the utilities be required to prepare and apply 170
common guidelines on how to conduct and document the evaluation of their route selections to all expansion projects.

5.2.6 Energy Probe, the Green Energy Coalition, and Pollution Probe proposed that the utilities should 171
be required to adopt as a principle that there should be "no net loss" of local environmental resources as a result of their system expansion activities. Where a utility is unable to offset the environmental impacts of its system expansion activities, the utility should make best efforts to create an offsetting environmental resource to meet the "no net loss" principle.

5.3 BOARD'S COMMENTS AND FINDINGS 172

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less 173
public scrutiny of the financial and economic evaluation of individual system expansion projects. However this does not imply that there should be any decrease in the necessary level of environmental assessment of projects by the utilities, or the documentation of this work, as these matters will continue to be reviewed by the Board.

5.3.2 The planning principles described in the Board's Environmental Guidelines shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined by the utilities in a manner consistent with the Environmental Guidelines based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. Environmental significance is to be determined based on the expected impacts of a particular project, not on whether the feature is covered by the utility's environmental guidelines. 174

5.3.3 To assist in determining what level of planning, investigation and reporting is necessary, the Board finds that the utilities shall jointly develop a common set of environmental screening criteria to determine if significant environmental features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be jointly developed and applied by each utility depending on the impacts expected as determined through the screening process. The criteria and corresponding requirements can be in the form of a checklist. The Board will review the screening criteria and the corresponding planning, documentation and reporting requirements for inclusion in the Environmental Guidelines. The Board expects the utilities to submit this material to the Board by June 1, 1998. Was page 24 175

5.3.4 Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters shall identify potential impacts through the screening process and determine the level of planning required. Depending on the significance of the potential impacts anticipated, the decision on the level of planning may involve additional environmental specialists of the utility, external consultants and other affected parties. 176

5.3.5 Depending on the level of significance of the environmental feature(s) encountered, the planning may involve alternative routing/siting considerations, detailed mitigation requirements and/or public and/or agency review. It is expected that the criteria and requirements will be updated from time to time by the utilities in consultation with other interested parties and reviewed by the Board for inclusion in updated Board Environmental Guidelines. 177

5.3.6 Where alternative routes or sites are investigated, the Board expects that the preferred alternative will be chosen based on an optimization of the particular environmental, social and financial criteria for the project. Decisions on the relative importance of these criteria are to be made based on the specific environmental features encountered and their significance, rather than deciding in advance that financial criteria have priority. Was page 25 178

5.3.7 In those cases where the significance of environmental features may be in question or the planning requirements are not clear, the utilities are expected to consult with environmental specialists, Board Staff and affected parties. The Board expects that as experience is gained, consultation will be necessary only in unusual cases. In all cases however, it is expected that provincial and local agency requirements (permits, licences) shall be obtained where necessary and that the utilities will apply their standard guidelines, drawings, and specifications. 179

5.3.8 The Board finds that further examination of the "no net loss" principle is unnecessary in this proceeding in light of the Board's specified environmental planning requirements. 180

Blank page Was page 26 181

6. MONITORING AND REPORTING REQUIREMENTS Was page 27 182

6.1 INTERIM REPORT CONCLUSIONS 183

6.1.1 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.* 184

6.1.2 *Despite the advantages of a portfolio approach, the Board is of the view that certain containment practices should be put in place in order to ensure that:* 185

- *ratepayers are protected from financially risky decisions on expansion by the utilities;* 186
- *the utilities make decisions on which projects should proceed in an even-handed manner;* 187
- *the cumulative impact on rates is not undue in any given year;* 188
- *the continued expansion of natural gas service is in the overall public interest; and* 189
- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.* 190

6.1.3 *Utility shareholders will be held responsible for any significant variation in the forecast of customer attachments, volumes and costs from the aggregate portfolio. The Board expects the utilities to make proposals in the next phase of this proceeding on how variances from the aggregate forecast should be treated in order to appropriately share the risk between ratepayers and shareholders. In considering how the risk should be shared, the utilities may want to review their policies on obtaining financial assurances from new large volume customers.* 191

6.1.4 *The Board also expects the utilities to develop proposals on the appropriate method to use to monitor the variation between forecast and actual profitability of their distribution system expansion portfolios.* Was page 28 192

6.1.5 *However, the Board finds that it is in the public interest to require the utilities to demonstrate that it continues to be in the overall public interest to expand the natural gas distribution systems from an aggregate economic, social and environmental point of view. Therefore, the Board will require utilities to file the results of a societal cost test ["SCT"] of their overall portfolios of distribution system expansion when seeking approval of their portfolios. The societal cost test could include monetized, non-monetized and qualitative components. To this end, the Board requests the utilities* 193 *to develop a common evaluation method, that would be cost-effective, that would adequately characterize performance, and that would be relatively straightforward to apply.*

6.1.6 *The Board expects the utilities to develop common reporting requirements so that the utilities' forecast P.I.s, customer attachments, volumes and costs can be compared to actuals on a portfolio basis and, if need be, on a project specific basis. This information shall be put on the record in the rates cases to serve as a benchmark.* 194

6.1.7 *The Board expects that under the portfolio approach the Stage I financial feasibility P.I. will be calculated for each proposed project as well as for the portfolio of infill projects. For the purposes of calculating the P.I. of the infill portfolio, infill projects are defined as the extension of mains and service attachments in existing service areas, but does not include service lines to individual customers off existing mains.* 195

6.1.8 *All the P.I.s of the proposed projects and the infill portfolio will be aggregated to calculate the overall portfolio P.I. at a given time for each utility.* 196

6.2 POSITIONS OF THE PARTIES 197

6.2.1 The ADR Agreement proposed that the utilities file Test Year and Historic Year information as part of their rates cases. This information would include the capital amounts, profitability and rate impacts of the Investment Portfolio and the Rolling Project Portfolio; actual expenditures on reinforcement costs; and specific customer attachment information on a set of randomly selected projects. 198

6.2.2 The ADR Agreement also proposed that each utility file in its rate case a projected NPV of the results of a SCT for the Investment Portfolio for the test year. The results would be presented both with and without monetized externality costs and benefits. 199

Was page 29

6.2.3 The parties to the Dissent Document submitted that the ADR Agreement fails to meet the Board's direction in the Interim Decision because: 200

- the ADR Agreement does not require the utilities to report the P.I.s of their Investment Portfolios or any individual project within their Investment Portfolios; 201

- the ADR Agreement does not require the utilities to report the forecast aggregate NPV and P.I. of the test year's projects that have negative P.I.s (information necessary to address the Board's concern with respect to economic efficiency); and 202

- the ADR Agreement does not require the utilities to put on the record in their rates cases project specific P.I.s, customer attachments, volumes and cost data so that project specific information can serve as a benchmark for monitoring performance on an on-going basis. 203

6.2.4 The parties to the Dissent Document further submitted that the ADR Agreement fell short because: 204

- there is no commitment to provide a comparison of actual and forecast volumes; 205

- there is no commitment to provide a comparison of actual and forecast capital expenditures for the Investment Portfolio; and 206

- the utilities are only committed to providing a comparison of their actual and forecast customer attachments for the first three years of a project's life, which does not cover the remaining 7 years in a project's 10 year customer attachment forecast period. 207

The parties to the Dissent Document proposed that the utilities should be required to file portfolio and project specific information for the historic, bridge and test years. 208

6.3 BOARD'S COMMENTS AND FINDINGS Was page 30 209

6.3.1 The Board believes that the principles outlined in the Interim Report should form the basis of the monitoring and reporting requirements. 210

<u>Rate Case Review</u> 211

6.3.2 The Board directs that the utilities file, in their respective rates cases, a forecast NPV and P.I. of the test year Investment Portfolio. In subsequent rates cases, each utility will report to the Board on the actual results of the Investment Portfolio. 212

6.3.3 The actual results of the Investment Portfolio will present the NPV and the P.I. taking into account the capital spent, the number of customers attached and the revenues received from the customers attached in the most recent historical year for which there is full data. Volume usage for larger commercial and industrial customers will be individually estimated to more closely reflect actual annual volumes. 213

6.3.4 Each utility will, in its rates case, provide an analysis of the estimated rate impact of its Investment Portfolio in the first five years of service. As referred to earlier, the Board found the material filed by Consumers Gas in E.B.R.O. 495 at Exhibit I, Tab 7, Schedule 8, to be a good example of the information necessary, but would be further assisted if the impacts were broken down by rate class. The Board directs that such a breakdown be included in the required impact analysis. 214

6.3.5 As noted earlier, the Board also wishes the utilities to use a standard rate impact test or measure similar to the R.I.M. test used to assess DSM program impacts. This measure should present the following information in aggregate and by rate class: 215

- impact of the Investment Portfolio cash flow on the test year revenue deficiency; and Was page 31 216

- the ratio of incremental revenues to costs in the test year and subsequent three years. 217

6.3.6 The Board notes that in recent rates cases both Centra and Consumers Gas have significantly overspent their Board-approved capital budgets, particularly in the bridge year. In its E.B.R.O. 493/494 Decision the Board set out the criteria of *affordability* and *rate stability* as key factors affecting the capital budget and additions to rate base, which the Board will consider in assessing prudence of expenditures. 218

6.3.7 The Board notes that the addition of capital for assets such as Information Technology and Customer Information Systems may have significant impacts on both the level of capital expenditure and year to year additions to rate base. The Board in its E.B.R.O. 493/494 Decision suggested that affordability criteria be applied to develop ceilings for capital expenditures and rate stability criteria be used to manage the scheduling of expenditures on more discretionary projects in conjunction with system expansion projects. In addition, in E.B.R.O. 495 the Board expressed its concern about the upward pressure on rates resulting from continual system expansion, and concluded that, for ratemaking purposes, expenditures above overall Board-approved levels in various categories ("envelopes") of the capital budget could not automatically be included in the Company's proposed rate base for the next fiscal year. In addition, the Board cautioned that the Company would be required to prove the reasonableness of its capital expenditures within each envelope, even if the expenditures were at or below the Board approved level. 219

6.3.8 The Board expects that the concerns raised in these recent rate cases regarding affordability and rate stability will be addressed in the utilities' plans under the portfolio approach. 220

6.3.9 The Board will treat variances between actual and forecast portfolio NPVs in the same manner as for other forecast test year variables. The utilities will provide explanations of the reasons for the variations and the corrective actions taken or proposed. The Board will judge the degree to which the cost impacts should be apportioned between the shareholder and the ratepayers. 221

6.3.10 The Board agrees with the ADR proposal for portfolio level SCT analysis, monitoring and reporting, using a test that is consistent with the treatment of the SCT for DSM. Was page 32 222

Ongoing Monitoring and Reporting 223

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B[247] are to streamline the process of approval of system expansion projects and achieve a commonality of approach between the utilities, while ensuring that ratepayers are protected against the impacts of either over-aggressive, or financially inappropriate, system expansion by the utilities. 224

6.3.12 The Board believes that the achievement of these objectives requires periodic standardized reporting to the Board, as well as the filing of information in rate cases in order to allow the prudence of 225 the utilities' actions and rate impacts to be reviewed. These reviews should appropriately be rate focussed with account taken of both short-term and long-term costs and benefits to ratepayers.

6.3.13 The Board considers that, in general, the ADR Agreement proposals in the section *Monitoring the Performance of the Portfolios/Short Term Rate Impacts*, provide a reasonable point of departure and that experience should show whether the content and timing of the monitoring and reporting requirements are adequate. The Board will require filing of the P.I.s of the portfolios as well as the NPVs. The adjusted monitoring requirements are included in the Guidelines in Appendix B. 226

6.3.14 The Board emphasizes that the utilities must maintain clear records at a project specific level that will allow for inspection and/or reporting of individual projects as may be deemed necessary from time to time. 227

6.3.15 The Board will require quarterly filing of the monthly reports on the Rolling Project Portfolio and total capital expenditures in order to monitor performance. Was page 33 228

6.3.16 The approach to environmental planning outlined above should simplify the documentation requirements. The sampling process and reporting required in the Guidelines will ensure consistency across projects and between utilities and ensure compliance with the Board's environmental planning requirements. 229

Blank page Was page 34 230

Was page 35 231

7. COMPLETION OF THE PROCEEDING AND COSTS

7.1 COMPLETION OF THE PROCEEDING 232

7.1.1 The Board has reviewed the letters of comment setting out the positions of various parties on the ADR Agreement and the Dissent Document. The Board is of the view that it would not be in the public interest at this stage to hold additional hearings on this matter. Rather, the Board believes that the public interest is better served by proceeding with the implementation of the Guidelines included in Appendix B[247] of this Report. 233

7.1.2 The Board directs that the Guidelines shall be implemented as soon as possible, but no later than the 1999 fiscal year for each of the utilities. The Guidelines will be subject to future review by the Board in the light of experience gained in their application. 234

7.2 COSTS 235

7.2.1 In the Board's Interim Decision of August 15, 1996 the parties to the proceeding were directed to submit cost claims for that phase of the proceeding. The Board made an interim cost award to those parties requesting one. 236

7.2.2 The Board directs all parties who wish to do so, to submit their final claim for costs with the Board and a copy to each of the utilities, taking into account the interim cost award (if applicable) by February 20, 1998. Comments from the utilities are to be filed by March 2, 1998 and reply by parties by March 16, 1998. The Board will issue its Cost Award Decision and Order in this proceeding in due course. 237

Was page 36 238

7.2.3 The Board directs the utilities to pay the Board's costs of, and incidental to the proceeding upon receipt of the Board's invoice.

7.2.4 The Board directs that all costs be apportioned on a 50:50 basis between Consumers Gas and Union/Centra Gas. 239

DATED AT TORONTO January 30, 1998.

G.A. Dominy
Vice Chair and Presiding Member

R.M.R. Higgin
Member

J. B. Simon
Member

APPENDIX A Was Appendix, preliminary page 1 241

Parties Concurring with the ADR Agreement 242

Board Staff 243
City of Kitchener
The Consumers' Gas Company Ltd.
Consumers' Association of Canada
Federation of Northern Ontario Municipalities
Northwestern Ontario Municipal Association
Ontario Federation of Agriculture*
Ontario Pipeline Landowners Association*
Ontario Coalition Against Poverty
Union Gas Limited and Centra Gas Ontario Inc.*

Parties Substantially Supporting the Dissent Document 244

Canadian Industry Program for Energy Conservation* 245
Canadian Association of Energy Service Companies
Energy Probe
Green Energy Coalition*
Industrial Gas Users Association*
Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
Ontario Native Alliance
Pollution Probe

* Letter of Comment Received 246

Was Appendix, preliminary page 2 247

APPENDIXB ONTARIO ENERGY BOARD GUIDELINES FOR ASSESSING AND REPORTING ON NATURAL GAS SYSTEM EXPANSION IN ONTARIO

1998 248

Was Appendix, preliminary page 3 249

CONTENTS

Was Appendix, page 1 258

I. OVERVIEW - PURPOSE AND OBJECTIVE OF THE GUIDELINES

The Ontario Energy Board ("OEB", "Board") Guidelines for Assessing and Reporting on Natural Gas System Expansion In Ontario ("The Guidelines") provide a common analysis and reporting framework to be applied by regulated Ontario Local Distribution Companies - Union Gas Limited and The Consumers' Gas Company Ltd. ("the utilities") to natural gas distribution system expansion. The principles upon which the Guidelines are based reflect the Board's conclusions in its Distribution System Expansion Reports under Board File No. E.B.O. 188. (Interim Report[12JM1-0:1] dated August 15, 1996; Final Report[1] dated January 30, 1998). 259

Portfolio Approach 260

The main change from prior policy and practice is the use of a portfolio approach, as opposed to a project-by-project approach, to the planning, analysis, management and reporting of distribution system expansion projects. The intent of the portfolio approach is to provide the utilities a greater degree of flexibility in determining which projects to undertake, while the Board retains overall regulatory control to ensure no undue cross subsidy or rate impacts result from distribution system expansion. 261

Financial Feasibility Analyses 262

The Guidelines provide the utilities with direction with respect to the structure of their system expansion portfolios and the methods for conducting financial feasibility analyses at both the individual project level and the portfolio level. The Guidelines standardize the elements to be used in the discounted cash flow ("DCF") analysis as well as establish the parameters for the costs and revenues that are the inputs to that analysis. 263

Reporting 264

The Guidelines establish a mechanism to evaluate the performance of each of the utilities' distribution expansion activities on a portfolio basis and on an individual project basis. The Guidelines also outline reporting requirements for system expansion plans and post expansion impacts. The forecast rate impacts of a utility's expansion plans will be presented in rates case filings on a prospective test year basis. 265

These reporting requirements are intended to provide the Board and interested parties with sufficient information to monitor the utilities' expansion activities and their associated rate impacts. The performance of the utilities related to implementation of these Guidelines will be evaluated as part of each utility's rates case. 266

Customer Connection Policies Was Appendix, page 2 267

Part of the utilities' management of distribution system expansion will be the provision of common customer connection policies. These will include policies relating to service line fees, customer contributions to otherwise financially unfeasible projects and for projects dominated by one or more large volume customers. 268

Environmental Considerations 269

To ensure that the utilities plan and construct system expansion facilities in an environmentally acceptable manner, the Guidelines also address the routing and environmental planning, documentation and reporting requirements for distribution expansion projects. 270

Was Appendix, page 3

1. SYSTEM EXPANSION PORTFOLIOS 271

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching to existing mains). The Investment Portfolio is to include a forecast of normalized system reinforcement costs. 273

The Investment Portfolio will be designed to achieve a profitability index ("PI") *greater* than 1.0. 274

1.2 Rolling Project Portfolio 275

Each of the utilities will maintain a rolling 12 month distribution expansion portfolio (the "Rolling Project Portfolio") updated monthly, as an ongoing management tool for estimation of the future impacts of capital expenditures associated with distribution system expansion. The Rolling Project Portfolio will exclude those customers requiring only a service lateral from an existing main. 276

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the past twelve months for the Rolling Project Portfolio. It will include all future customer attachments, revenues and costs on the basis of the life cycle of each of the projects making up the Portfolio. 277

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

The standard test for determining the financial feasibility at both the project and the portfolio level will be a DCF analysis, as set out below. 279

2.1 DCF Calculation and Common Elements 280

The DCF calculation for a Portfolio will be based on a set of common elements. For <u>revenue forecasting</u>, the common elements will be as follows: 281

(a) for the Rolling Project Portfolio, total forecasted customer attachments over the Customer Attachment Horizon for each project; 282

(b) for the Investment Portfolio, a forecast of all customers to be added in the Test Year; 283

(c) an estimate of average use per added customer which reflects the mix of customers to be added; 284

(d) a factor which reflects the timing of forecasted customer additions; and 285

Was Appendix, page 4

(e) rates derived from the existing rate schedules for the particular utility, net of the gas commodity component. 286

For capital costs, the common elements will be as follows: 287

(a) an estimate of all costs directly associated with the attachment of the forecast customer additions, including costs of distribution mains, services, customer stations, distribution stations, land and land rights; 288

(b) an estimate of incremental overheads applicable to distribution expansion at the portfolio level; and 289

(c) an estimate of the normalized system reinforcement costs. 290

For expense forecasting, the common elements will be as follows: 291

(a) gas costs as used in revenue forecasts (excluding commodity costs); 292

(b) incremental operating and maintenance costs; 293

(c) income and capital taxes based on tax rates underpinning the existing rate schedules; and 294

(d) municipal property taxes based on projected levels. 295

2.2 Specific Parameters 296

Specific parameters of the common elements include the following: 297

(a) a 10 year customer attachment horizon;. 298

(b) a customer revenue horizon of 40 years from the in service date of the initial mains (20 years for large volume customers); 299

(c) a discount rate equal to the incremental after-tax cost of capital based on the prospective capital mix, debt and preference share cost rates, and the latest approved rate of return on common equity; 300

(d) discounting reflecting the true timing of expenditures. Up-front capital expenditures will be discounted at the beginning of the project year and capital expended throughout the year will be mid-year discounted, as will revenue, gas costs, and operating and maintenance expenditures; and 301

(e) gas costs based on the weighted average cost of gas ("WACOG") excluding commodity costs. 302

Was Appendix, page 5

3. MONITORING PORTFOLIO PERFORMANCE AND SHORT-TERM RATE IMPACTS 303

3.1 Rates Case Filings 304

The following information will be filed in each rates case: 305

Test Year 306

(a) the Investment Portfolio, including NPV, the total capital in the portfolio and the portfolio PI; 307

(b) an estimate of the aggregate NPV of all new facilities requiring a new franchise and/or certificate of public convenience and necessity and of all "infills" (i.e. main extensions and service attachments in existing service areas excluding service lines to customers off existing mains) based on extrapolated historical data; 308

(c) an estimate of the Test Year rate impacts of the Investment Portfolio based on the: 309

(i) contribution to annual revenue requirement; 310

(ii) Rate Impact Measure presented as the ratio of added revenue to costs for each customer class; and 311

(iii) class-specific estimated percent rate and annual average bill increases. 312

(d) estimates of the NPV and the benefit-cost ratio for the Investment Portfolio using a Societal Cost Test ("SCT"), defined in the Report of the Board, E.B.O. 169 III, as an evaluation of the costs and/or benefits accruing to society as a whole, due to an activity. The SCT analysis should be consistent with that used for the utilities' DSM programs. The benefit-cost ratio shall be presented with and without monetized externalities. 313

Historic Year: 314

(a) the Historic Year Investment Portfolio, including the NPV, total capital in the portfolio, and the portfolio PI; 315

(b) the aggregate NPV, the total capital, and the portfolio PI for: 316

- (i) the Rolling Project Portfolio at the end of the historic year; 317
- (ii) all completed projects with negative NPVs; 318
- (iii) all completed projects with positive NPVs; 319

(c) upon the request of the Board, a list of the projected results of individual extensions included in the Rolling Project Portfolio; 320

(d) actual expenditures on reinforcement projects; and 321

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data. Was Appendix, page 6 322

3.2 Ongoing Monitoring Information 323

The utilities shall establish a process to allow the Board to monitor the performance of their distribution system expansion project portfolios including financial and environmental requirements. 324

A. Financial Monitoring 325

In consultation with Board Staff, the utilities shall select projects from their Rolling Project Portfolios on an annual basis and shall file the following with respect to the sample: 326

- (a) the cumulative number of customers attached at the end of the 3rd full year and the associated revenues and costs; and 327
- (b) the corresponding year 3 customer attachment forecasts and associated revenues and costs. 328

B. Environmental Monitoring 329

In consultation with Board Staff, the utilities shall select a set of completed projects and file data 330 on those projects on an annual basis as described below. The projects chosen should be selected in a random, stratified manner, reflecting the range of environmental impacts encountered in the time period and the various levels of environmental planning, documentation and reporting required. The selection should be reviewed by an independent auditing group within the utility, which group shall include (a) trained environmental auditor(s). The utility shall file the following with respect to each sample:

1. a description of how the project complied with the Board-approved environmental screen- 331 ing, planning, documentation and reporting requirements;

2. a table of significant features, how they were avoided or mitigated, and resulting impacts; 332

3. a table displaying the concerns raised by affected parties including member ministries of 333 the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns;

4. issues of significance arising from any post-construction monitoring; 334

5. where alternatives were investigated, a display of alternatives (routes/sites) which show 335 the various trade-offs between customer attachments, and environmental, social and financial costs and a discussion of how the preferred alternative was chosen;

6. evidence that all necessary approvals (permits, licences) were obtained; and Was Appendix, page 7 336

7. forecast versus actual costs of the environmental planning. 337

3.3 Risks of Non-performance 338

In the event that the actual results of the Investment Portfolio do not produce a positive NPV or a 339 PI of at least 1.0, the following will occur:

(a) the utility will be required to provide a complete variance explanation in its rates case and 340 the Board will determine whether or not an acceptable explanation has been provided; and

(b) the implications of a negative NPV or PI less than 1.0 will be determined by the Board on 341 a case by case basis.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES 342

The utilities will maintain a clear set of common Board-approved Customer Connection and Contribution in Aid Policies. 343

The criteria for contributions in aid of construction for service lines and mains will apply to all customer classes. If there is a reasonable expectation of further expansion, the contribution in aid of construction will take into account the future load growth potential and timing of any such expansion. 344

The Customer Connection and Contribution in Aid Policies shall, as a minimum, include the following: 345

- Requirements for payment for all, or part, of a customer service line connection, including the specific criteria and the quantum of, or formula for calculating, the total or excess service line fees and other charges. 346
- Requirements for contributions in aid of construction for connection of individual customers, subdivisions or communities requiring main extensions that would not otherwise be included in the Investment or Rolling Project Portfolios. 347
- Requirements for contributions in aid of construction for expansion projects dominated by one or more large volume customers. 348

5. ENVIRONMENTAL REQUIREMENTS FOR DISTRIBUTION FOR SYSTEM EXPANSION PROJECTS 349

The planning principles described in the Board's "Environmental Guidelines for the Location, Construction, and Operation of Hydrocarbon Pipelines and Facilities In Ontario (1995)" shall also apply to distribution expansion projects undertaken by the utilities. The level of detail required, the degree of public consultation and the level of alternative route/site evaluation should be determined based on a review of the environmental (biophysical and socio-economic) significance of features potentially impacted by a proposed project. 350

Was Appendix, page 8 351

The utilities shall apply environmental screening criteria to determine when significant features may be impacted during the construction or the operation of the facility. Corresponding planning, documentation, and reporting requirements are to be applied depending on the impacts expected as determined through the screening process.

Once the study area for the project is determined, a regional officer of the utility who is familiar with the study area and has been trained in environmental matters, shall identify potential impacts through the screening process and determine the level of planning required. Depending on the 352 significance of the potential impacts anticipated, the planning requirements may involve environmental specialists of the utility, external consultants or other affected parties.

353

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications.

354

6. DOCUMENTATION, RECORD KEEPING AND REPORTING

355

The utilities will maintain documentation for all projects which are to be included in the Rolling Project Portfolio. A record of the DCF analysis conducted for each project in the Rolling Project Portfolio shall be available for review upon request of the Board. The performance tracking of individual projects shall be as described in Section 3 of these Guidelines.

356

The utilities will maintain a record of the environmental planning, documentation and reporting requirements associated with all projects and Environmental Reports for those projects deemed to have significant environmental impacts.

357

For all expansion projects in the Rolling Project Portfolio with a capital cost greater than $500,000 ("major projects") the utilities shall file the NPV and DCF analysis in each rate case and shall keep a record of forecast and actual customer attachments for a period of three years after construction is completed. In addition, the utilities shall also file in each rate case, the NPV and DCF analysis for all major projects planned for the test year. Upon request of the Board, the utilities shall file forecast and actual customer attachments for major projects.

358

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations.

Was Appendix, schedule page 1 359

SCHEDULE1 DISCOUNTED CASH FLOW METHODOLOGY

360

<u>Net Present Value ("NPV")</u> *= Present Value ("PV") of Operating Cash Flow + PV of CCA Tax Shield - PV of Capital*

<u>Profitability Index ("PI")</u> = *<u>PV of Operating Cash Flow + PV of CCA Tax Shield</u>*

(PV of Capital)

361

1. <u>PV of Operating Cash Flow</u> *= PV of Net Operating Cash (before taxes) - PV of Taxes*

a)	PV of Net Operating Cash	=	PV of Net Operating Cash Discounted at the Company's discount rate for the customer revenue horizon. Mid-year discounting is applied.
	Net Operating Cash	=	*(Annual Gas Revenue - Annual Gas Costs - Annual O&M)*
	Annual Gas Revenue	=	*Customer Additions * Consumption Estimates per Customer * Revenue Rate per* m^3
	Annual Gas Cost	=	*Customer Additions * Consumption Estimates per Customer * Gas Costs per* m^3 *net of commodity costs*
	Annual O&M	=	*Customer Additions * Annual Marginal O&M Cost/customer*

Was Appendix, schedule page 2 362

b)	PV of Taxes	=	PV of Municipal Taxes + PV of Capital Taxes + PV of Income Taxes (before Interest tax shield)
	Annual Municipal Tax	=	*Municipal Tax Rate * (Total Capital Cost)*
	Total Capital Cost	=	*(Mains Investment + Customer Related Investment + Overheads at portfolio level)*
	Annual Capital Taxes	=	*(Capital Tax Rate) * (Closing Undepreciated Capital Cost Balance)*
	Annual Capital Tax	=	*(Capital Tax Rate) * (Net Operating Cash - Annual Municipal Tax - Annual Capital Tax)*

The Capital Tax Rate is a combination of the Provincial Capital Tax Rate and the Large Corporation Tax (Grossed up for income tax effect where appropriate).

363

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon.

364

2. <u>PV of Capital</u> = *PV of (Total Annual Capital Expenditures - Annual Contributions)*

a) PV of Total Annual Capital Expenditures

Total Annual Capital Expenditures over the customer's revenue horizon discounted to time zero

Total Annual Capital Expenditure = *(Mains Investment + Customer Specific Capital + Overheads at the Portfolio level)*

Was Appendix, schedule page 3 365

b) Annual Contributions

Annual Contributions = *Cash payments (or principal portions of payments over time) received as Contributions in Aid of Construction*

366

Note: Above is discounted to the beginning of year one over the customer addition horizon.

367

3. <u>PV of CCA Tax Shield</u>

PV of the CCA Tax Shield on [Total Annual Capital]

The PV of the perpetual tax shield may be calculated as:

PV at time zero of :

$$\frac{[(\text{Income Tax Rate}) * (\text{CCA Rate}) * \text{Annual Total Capital}]}{(\text{CCA Rate} + \text{Discount Rate})}$$

or,

Calculated annually and present valued in the PV of Taxes calculation.

Note: An adjustment is added to account for the $^1/_2$ year CCA rule. 368

369

4. Discount Rate

PV is calculated with an incremental, after-tax discount rate.

Tab 7

EBO 134, Report of the Board, Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario, June 1, 1987

Rep: OEB
Doc: 11L1X
Rev: 0

E.B.O. 134 1

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, Chapter 332; 2

AND IN THE MATTER OF a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario. 3

BEFORE: J.C. Butler, Vice-Chairman and Presiding Member 4

J.A. DeKort, Member 5

M.A. Daub, Member 6

7

REPORT OF THE BOARD

June 1, 1987 8

ISBN 0-7729-2610-7 9

Was Page i. See Image [OEB:11L1W-0:2]

TABLE OF CONTENTS 10

Was Page ii. See Image [OEB:11L1W-0:3]

Was Page 1. See Image [OEB:11L1W-0:4]

1. INTRODUCTION 18

1.1 In the summer of 1986, the Ontario Energy Board (the Board) examined six applications by The Consumers' Gas Company Ltd. (Consumers') to provide service to the Town of Deep River, the Village of Chalk River and the Township of Rolph, Buchanan, Wylie and McKay (E.B.L.O. 216 et al.). The Board denied these applications and, in its Reasons for Decision, the Board concluded that the criteria used by the utilities to assess and justify system expansion should be reviewed. 19

1.2 On January 9, 1987, Notice of a Review by the Ontario Energy Board of the Expansion of the Natural Gas System in Ontario (the Review) was issued. 20

Was Page 2. See Image [OEB:11L1W-0:5]

2. BACKGROUND 21

2.1 There are three major gas distributors in Ontario which together serve approximately 1,500,000 customers: Consumers', ICG Utilities (Ontario) Ltd (ICG) and Union Gas Limited (Union). Each distributor operates within a franchised area. 22

2.2 Consumers' is Canada's largest natural gas distributor, serving about 850,000 customers in southern, central and eastern Ontario, western Quebec and northern New York State. The company has assets of about $1.4 billion and distributes about 9,000 10(6)m(3) of gas annually through its network of 18,657 kilometres of mains. 23

2.3 ICG operates a natural gas distribution system consisting of approximately 5,600 kilometres of 24 pipeline in northwestern, northern and eastern

Was Page 3. See Image [OEB:11L1W-0:6]

Ontario. ICG's utility assets are valued at almost $400 million. ICG delivers approximately 3,100 10(3)m(3) of gas annually and serves approximately 163,000 customers. 25

2.4 Union operates a fully integrated gas distribution system employing storage, transmission and distribution facilities in southwestern Ontario. It sells over 7,300 10(6)m(3) of gas annually. Union also transports and stores about 5,700 10(6)m(3) of gas annually for other utilities and is Ontario's largest operator of underground storage pools with a developed capacity of 2,700 10(6)m(3). Union's utility assets are approximately $900 million. 26

2.5 In 1958, TransCanada Pipelines Limited (TCPL) completed its interprovincial pipeline from the Alberta-Saskatchewan border to Quebec, and western Canadian natural gas became widely available in Ontario. During the next two decades, the demand for natural gas in Ontario grew rapidly due to its abundant supply and relatively low price. This demand in turn led to a major expansion of distribution facilities by Ontario's natural gas utilities. 27

2.6 By the late 1970's, most of the system expansion taking place pertained to new subdivisions, upgrading of existing pipeline capacity and development of storage facilities. 28

Was Page 4. See Image [OEB:11L1W-0:7]

2.7 In the early 1980's, expansion of the natural gas distribution network was stimulated by federal government programs designed to reduce Canada's dependence on imported oil. One of these programs, the Distribution System Expansion Program (DSEP), administered by The Department of Energy, Mines and Resources (EMR) provided funds to the gas utilities of Ontario in the form of contributions in aid of construction to assist in expansion of their distribution system. 29

2.8 DSEP was designed to facilitate specific types of system expansion projects. The key criteria for funding such projects were the lack of financial viability and the volume of oil that gas would displace. 30

2.9 Another program, the Canada Oil Substitution Program (COSP), provided a grant to homeowners who converted from oil to natural gas. This program encouraged oil customers to convert to natural gas. 31

2.10 These EMR programs which encouraged expansion of the natural gas distribution system were phased out in 1984 and 1985. 32

Need for Review 33

2.11 As noted above, in the summer of 1986 the Board examined six applications from Consumers' for 34

Was Page 5. See Image [OEB:11L1W-0:8]

leave to construct gate stations and pipelines and for franchises and certificates to serve the Village of Chalk River, the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, in the County of Renfrew. 35

2.12 The Board denied the applications as the project did not meet Consumers' fifth-year rate of return feasibility test. In its Reasons for Decision the Board noted that the impact on the public interest, through either granting or denying gas service to the municipalities in question, was not adequately presented in the evidence. 36

2.13 The Board indicated in its Reasons for Decision that certain important questions concerning system expansion to smaller communities should be considered: 37

- with DSEP discontinued, what are the means whereby marginally uneconomic areas of Ontario are to be served, if at all; 38

- what is the role of the Board in the light of the removal of DSEP and to what extent should it be encouraging gas service to marginally uneconomic areas; 39

- with Ontario utilities facing mature markets, is expansion into uneconomic areas appropriate; 40

- should the shareholders or customers of utilities subsidize uneconomic expansion into smaller communities; 41

Was Page 6. See Image [OEB:11L1W-0:9]

- are there lower limits of return that should be permitted on a project basis? Are size of project or amount of subsidy factors that should be considered in assessing a project; 42

- have the changing circumstances with respect to energy resulted in the test of public interest being changed; 43

- are the current methods used by the utilities for assessing the economic feasibility of projects appropriate and what changes, if any, should be made; 44

- should the economics of system expansion be considered on the basis of marginal/incremental costs or on a fully allocated cost basis? 45

2.14 The Board indicated that these issues would best be addressed outside the context of a specific application and that it would call a special hearing for this purpose some time in early 1987. The Board anticipated that the recommendations from that special hearing would assist in determining whether new guidelines should be developed for leave to construct applications. 46

Was Page 7. See Image [OEB:11L1W-0:10]

47

3. THE REVIEW

48

3.1 The Board's Notice of January 9, 1987, invited any party interested in system expansion in Ontario to participate in the Review. The procedure set out in the Notice was designed to obtain input by way of written submissions from participants responding to a discussion paper (the Discussion Paper) developed by Board staff. The procedure also provided for technical conferences or workshops to review outstanding issues.

49

3.2 Although public participation through written submission has not been used previously by this Board it has been successfully used in other jurisdictions (e.g. the National Energy Board). It was considered that this procedure would encourage a valued input from many parties who might not wish to incur the expense or invest the time required for an oral hearing. By adopting this process the Board hoped to obtain

Was Page 8. See Image [OEB:11L1W-0:11]

50

a broader and more diverse input to the Review in the most cost effective manner.

51

3.3 The Notice also set out the deadlines for each phase of the Review. Most were extended in order to accommodate the wishes of the participants.

52

3.4 The Notice was served on the Clerks in every Municipality in Ontario and was published in approximately 42 newspapers.

53

3.5 Parties who wished to participate in the Review were directed to indicate their intent, in writing, by January 28, 1987. That deadline was extended with the last participant being granted status on February 4, 1987. A total of 129 Letters of Participation were received. The following is a list of Participants:

54

Gas Distributors

55

The Consumers' Gas

Company Ltd. P.Y. Atkinson
K. Walker

56

ICG Utilities

(Ontario) Ltd D.E. Gibbons
J. Roland

57

Natural Resource

Gas Limited W.K. Ferguson

Union Gas Limited J.B. Jolley 58

Was Page 9. See Image [OEB:11L1W-0:12]

Municipalities 59

Township of Bosanquet C.P. McKenzie 60

County of Brant C.G. Spencer 61

Township of Brock G.S. Graham 62

Township of Burford B.M. Cadman 63

City of Burlington G.E. Goodman 64

Town of Chesley J. Albright 65

Town of Cobourg R.G. Stinson 66

Township of Dawn J. Langstaff 67

Town of Deep River R. Adam 68

Town of Dundas J.R. Gerrie 69

Township of Elma G.S. Tucker 70

Town of Flamborough R.G. Stewart 71

Township of Glanbrook H. Kooyman 72

Township of Golden R.G. LaCroix 73

Township of Haldimand M.P. Bosetti 74

The Regional Municipality 75

of Hamilton-Wentworth L.D. Turvey

Town of Kincardine G.R. Sutton 76

City of Kitchener J.A. Ryder 77

Township of Moore R.H. Whitman 78

Town of Napanee K.D. Deyo 79

The Regional Municipality 80

of Niagara A.R. Pierson

Was Page 10. See Image [OEB:11L1W-0:13]

Municipalities (cont'd) 81

City of North Bay R.F. Barton 82

Township of North 83

Dorchester C. Walton

Township of Oro R.W. Small 84

The Regional Municipality 85

of Ottawa-Carleton J.D. Cameron

Town of Paris P.H. Dearling 86

Town of Parry Sound W.E. Ewing 87

County of Peterborough W.D. Armstrong 88

Town of Simcoe D. Brunton 89

City of Toronto J. Rabinowitz 90
R.M. Feig

The Regional Municipality 91

of Waterloo S.A. Thorsen

Township of Westmeath P. Burn 92

Township of West Nissouri C.E. Babb 93

Town of Wiarton R.J. Kastner 94

Citizens 95

Trevor Allinson 96

Neil Baird 97

Charles and Shirley Barlow 98

Mr. & Mrs. J. Blakely 99

Harold A. Boswell 100

Reg Bright 101

Denine Brown 102

Was Page 11. See Image [OEB:11L1W-0:14]

Citizens (cont'd) 103

Harold and Judith Cottom 104

A.H. and Ella de Quehen 105

David Dingwall 106

Dr. Mauro G. Di Pasquale 107

108

Was Page 12. See Image [OEB:11L1W-0:15]

Citizens-(cont'd) 127

Mr. & Mrs. E.S. & V.L. Morrison 128

L.G. McIlroy 129

Donna S. McGillis 130

Beverly Nicholls 131

Daniel A. Nicholls 132

Joan M. Nolasco 133

Don Mikel 134

Barry Octeau 135

Dr. B. Quarrington 136

George R.J. Rapai 137

Mr. & Mrs. Brian Rapsey 138

Graham & Jean Rogers 139

Steve Rowe 140

Mr. & Mrs. K. Savage 141

W.J., Violet and Steve Sawyer 142

Dirk J. Schmachtel 143

Daniel Scobie 144

Mark Scott, Edward E. Scott, Jane Scott 145

Richard Shapcott 146

Michael Sheehy 147

Mr. & Mrs. Donald E. Smith 148

Scott and Susan Stanley 149

Charles Stimac 150

Was Page 13. See Image [OEB:11L1W-0:16]

Citizens (cont'd) 151

Jo Anne St. James 152

Pat and Birgit Tunney 153

Mervyn Wells 154

Mr. & Mrs. George Welton 155

J.D. Williamson 156

Marilyn Williamson 157

P.W. Wilmer 158

G.M. and Glorya Woods 159

Other Participants 160

Alberta Petroleum Marketing 161

Commission S.F. McAllister

Association of 162

Municipalities of Ontario M. Dunbar

B.C. Hydro and Power 163

Authority E. C. Eddy

Brant County Federation of 164

Agriculture M. Sharp

Canadian Enerdata Limited R. Zarzeczny 165

Canadian Petroleum 166

Association D.B. Macnamara

C-I-L Inc. P.D. Jackson 167

Committee of Southwestern 168

Ontario Municipalities A.C. Wright

Concerned Citizens of 169

Haldimand G. Hinton

Dow Chemical Canada Inc. F.G. Marcinkow 170

Was Page 14. See Image [OEB:11L1W-0:17]

Other Participants (cont'd) 171

Eastont Integrative Services 172

Incorporated (E.I.S.I.) C.B. Walker

Energy Probe D.I. Poch 173

Foothills Pipe Lines 174

(Yukon) Ltd. H.N.E. Hobbs

Great Lakes Forest Products J.L. Davies 175

H. Rentsch Associates Ltd. H.E. Rentsch 176

Inco Limited T.W. Leishman 177

Independent Petroleum 178

Association of Canada R.G. DeWolf

Industrial Gas Users 179

Association P.C.P. Thompson, Q.C.
T. Bjerkelund

Lambton Gas Storage 180

Association A. Kimpe

Ministry of Energy I.B. MacOdrum 181

Monenco Consultants Limited D.H. Stevenson 182

Ontario Corn Producers' 183

Association D. LeDrew

Ontario Hydro C.R. Chorlton 184

Parry Sound Area Economic 185

Development Commission M.B. Stagg

Polysar Limited G.P. Sadvari 186

PSR Gas Ventures Inc. P.H. McMillan 187

Tecumseh Gas Storage 188

Limited P.Y. Atkinson

Thunder Bay-Atikokan Iain Angus, MP 189

Was Page 15. See Image [OEB:11L1W-0:18]

Other Participants (cont'd) 190

TransCanada PipeLines 191

Limited C.C. Black

Twin Elm Estates Ltd. G. Brothers 192

Board Staff Discussion Paper 193

3.6 The Discussion Paper outlined criteria previously used by the Board when assessing the public interest in system expansion projects and examined economic feasibility tests currently used by the gas distributors' when evaluating system expansion projects. In the Discussion Paper, Board staff also presented alternative feasibility tests to stimulate discussion and a critical re-evaluation of the tests now in place. 194

3.7 A copy of the Discussion Paper and Procedural Order-1 were provided to all participants. Procedural Order-1 set out the format for responses to the Discussion Paper. All responses were distributed to all participants and all participants were given the opportunity to reply to each others' responses. 195

3.8 The Board received 25 responses to the Discussion Paper and seven replies to those responses. 196

Was Page 16. See Image [OEB:11L1W-0:19]

Technical Conference 197

3.9 On March 8, 1987, Procedural Order-2 was issued indicating that a Technical Conference (the Conference) would be held on April 6, 1987, to discuss matters arising from the responses and replies of participants. 198

3.10 Procedural Order-3, issued March 27, 1987, indicated that the Conference would be held on April 9, 1987, and it would be conducted by Board staff. It also indicated that the following matters would be discussed: 199

- Public Interest; 200
- Existing Economic Tests;
- Economic Feasibility Tests presented in the Discussion Paper: and

- Contributions in Aid of Construction.

3.11 The Conference extended over two days and was attended by the following participants: 201

B. Taylor on behalf of Consumers' 202
D. Rewbotham
P. Davis

J. Hunter on behalf of ICG 203
D. Gibbons

J. Anderson on behalf of Union 204
P. Pastirik
D. McCash

Was Page 17. See Image [OEB:11L1W-0:20]

L. Smith on behalf of the Town N. Williamson of Deep River 205

E. de Quehen on behalf of the Public Interest Participants 206

D. Poch on behalf of Energy 207

P. Muldoon Probe 208

A. Ryder on behalf of the City of Kitchener 209

T. Loughlin on his own behalf 210

J. Thorne on behalf of the City of Toronto 211

K. Taylor on behalf of Western 212
Gas Marketing Limited,
an affiliate of Trans Canada
PipeLines Limited

3.12 The NDP Caucus, although not a participant, was represented by M. McVea. 213

3.13 A transcript of the Conference was taken and was made available to the Board along with all submissions by all participants in connection with the Review. These transcripts and all documents submitted to the Board as part of this Review are part of the Board's files and are available for public review. 214

Was Page 18. See Image [OEB:11L1W-0:21]
215

4. THE ROLE OF THE BOARD

216

4.1 There are three items of legislation which provide a comprehensive means to ensure the orderly and equitable provision of natural gas to Ontario consumers. These are the Ontario Energy Board Act (the OEB Act), R.S.O. 1980, Chapter 332, the Municipal Franchises Act, R.S.O. 1980, Chapter 309 (the MF Act) and the Public Utilities Act, R.S.O. 1980, Chapter 423 (the PU Act).

217

4.2 Before a utility can supply natural gas to a community, the utility is required under section 46 of the OEB Act to make an application for a Board Order granting leave to construct. If granted, it would permit the construction of the gas transmission line. Pursuant to section 8 of the MF Act, Board approval is required for the construction of works to supply gas and the actual supply of gas itself. Board approval is signified by the issuance of a certificate of public convenience and necessity.

Was Page 19. See Image [OEB:11L1W-0:22]
218

4.3 Under section 9 of the MF Act, the Board's approval is required of the terms and conditions contained in the municipal by-law and the Franchise Agreement under which the utility serves the municipality.

219

4.4 Under this legislation a distributor seeks Board approval to undertake a project and the Board is required to give or withhold such permission according to whether or not the Board judges the proposed project to be in the public interest. As part of its consideration of the public interest, the Board considers the impact of the proposed project on other customers and requires, in either the leave to construct or in the certificate of public convenience and necessity application, that an economic analysis be produced.

220

4.5 The Board also is required under section 19 of the OEB Act to examine the cost of all property plant and equipment included in the utility's proposed rate base, including the current capital budget, to assess whether these items will be "used or useful" in deciding if they should be included in rate base. This assessment includes all transmission, distribution and storage facilities which the distributor proposes to include in the capital budget. Rates are ultimately set by the Board to reflect the costs associated with those items in the rate base.

Was Page 20. See Image [OEB:11L1W-0:23]
221

5. THE PUBLIC INTEREST

222

5.1 The Board has a statutory obligation to consider the public interest before it makes a determination to grant or reject a leave to construct application for a proposed pipeline or station (Section 48 (8) of the OEB Act).

223

5.2 In the Discussion Paper and at the Conference, Board staff indicated that the Board typically employs a broad definition of the public interest which takes account of the facts and particular circumstances of each case.

5.3 Board staff presented a list of criteria related to the public interest. These are as follows: 224

1. Economic feasibility; 225

2. Community benefits 226

- o Industrial development 227
- o Alternative fuel considerations
- o Increased revenues to government (e.g. taxes) 228

Was Page 21. See Image [OEB:11L1W-0:24]

- o Local employment 229
- o Regional development;

3. Utility benefits; 230

4. Security of supply and safety; 231

5. System flexibility; 232

6. Route/site selection and landowners' concerns; 233

7. Environmental impact; 234

8. Government policy; and 235

9. Other factors. 236

Participants' Positions on the Public Interest 237

Consumers' 238

5.4 Consumers' stated that the principles that the Board should consider in determining public interest should be broad and wide ranging. 239

ICG 240

5.5 ICG noted that Board staff had included most of those public interest factors that the Board should consider. ICG advocated the view that each case is unique and the Board has to consider each application on its own merits to determine exactly what are the public interest concerns. 241

Was Page 22. See Image [OEB:11L1W-0:25]

Union 242

5.6 Union indicated that in its opinion the tendency over the last five or six years has been to consider the cost to existing customers as the primary public interest factor in evaluating system expansion projects. It also indicated that the other factors discussed by Board staff are probably equally important. 243

The City of Kitchener 244

5.7 The City of Kitchener submitted that decisions regarding uneconomic expansion of rate base should be made by the government and were thus beyond the scope of the Board's mandate. 245

Concerned Citizens of Haldimand; 246

Lynda Forbes and Public Interest Participants 247

5.8 These groups generally supported the Board's broad interpretation of the public interest but expressed concern that public interest factors not be incorporated into a formula. They also stressed the importance of a hearing for each application so that all matters regarding public interest could be considered by the Board. 248

Was Page 23. See Image [OEB:11L1W-0:26]

W. K. Hunt; 249
Brant County Federation of Agriculture;

Ontario Corn Producers' Association and Working Committee for the Expansion of Natural Gas Service in the Burford - Oakland Project Area 250

5.9 Several participants expressed a view that the widest public interest in Ontario would be served by provision of natural gas service to more rural municipalities. They expressed the concern that the agricultural sector has been forced to compete for system expansion with concentrated urban areas. Some groups argued that rural expansion should be heavily weighted in terms of public interest considerations since a healthy agricultural sector contributes to the well-being of the province as a whole. 251

Western Gas Marketing Limited 252

5.10 Western Gas Marketing Limited stated that public interest is a dynamic concept and also argued that none of the public interest factors are necessarily fully quantifiable at any given point in time. 253

IGUA 254

5.11 IGUA indicated that the costs associated with uneconomic system expansion ought to be borne by the customer classes that directly benefit from that expansion. 255

Was Page 24. See Image [OEB:11L1W-0:27]

Kincardine and District Recreation Board and Parry Sound Area Economic Development Corporation 256

5.12 This group expressed concern that with the end of DSEP, smaller communities in Ontario may not receive gas service. 257

The Board's Findings 258

5.13 The Board finds that it has jurisdiction to review all matters relating to the production, distribution, transmission and storage of natural gas. Mr. Justice Keith in reviewing the history and origins of the OEB Act, stated: 259

In my review that statute makes it crystal clear that all matters relating to or incidental to the production, distribution, transmission or storage of natural gas ... are under the exclusive jurisdiction of the Ontario Energy Board 260

These are all matters that are to be considered in the light of the general public interest and not local or parochial interests. The words "in the public interest" ... which I have quoted would seem to leave no room for doubt that it is the broad public interest that must be served. (Union Gas Limited vs. Township of Dawn, (1977) 76 D.L.R. 613) 261

5.14 The Board reiterates that the concept of public interest is dynamic and it must change according to the circumstances. The Board considers that the relevant criteria from those listed above, 262

Was Page 25. See Image [OEB:11L1W-0:28]

and others depending on the circumstances, should be addressed as fully as possible so that the Board has complete information on which to base its determination as to whether or not a project is in the public interest. 263

5.15 There can be no firm criteria for determining the public interest and the Board will not attempt to define these criteria closely. The weighting the Board attaches to each criterion considered can also change with the circumstances of a specific application. 264

5.16 When considering the public interest in prior proceedings the Board has been satisfied if the 265
welfare of the public is enhanced without imposing an undue burden on any individual, group or class. The Board will continue to be guided by this general principle in determining the extent to which gas service should be extended into other areas of the province.

5.17 The Board considers that system expansion should not be unlimited and that it is required to 266
continue to determine whether the expansion of gas service is in the public interest.

5.18 The Board has concerns with the concept of "economic feasibility" as it has been used in these 267
proceedings. These concerns will be examined in detail below. The Board considers

Was Page 26. See Image [OEB:11L1W-0:29]

that regardless of the "economic feasibility" test used to evaluate a project, it has not been, nor will it be, 268
the sole criterion examined. Even though "economic feasibility" is an important factor, it may be given more weight in some situations, and less in others such as safety or security of supply projects.

5.19 Any application to the Board should include evidence on all public interest criteria considered 269
relevant by the participants. Any data that can be quantified in a meaningful fashion should be presented that way with assumptions clearly stated.

5.20 The Board recognizes that the views of a local community may differ from those of an industrial 270
customer or of a utility. In reaching its decision, the Board attempts to accommodate differing interests in its assessment of the public interest. The greater the number of interests that are represented at a hearing, the more confidence the Board can have in its judgement regarding the public interest.

5.21 The Board therefore encourages wide participation in hearings regarding these matters. 271

Was Page 27. See Image [OEB:11L1W-0:30]

6. TESTS OF ECONOMIC FEASIBILITY 272

6.1 Because of its important influence on how the public interest is viewed, the question of economic 273
feasibility will be examined in detail and the existing and proposed "tests" to assist judgements about economic feasibility will be considered. In so doing, the Board's concerns with the concept of economic feasibility will be developed.

6.2 Over the years, the Ontario gas distribution utilities have refined the economic feasibility tests 274
used to evaluate system expansion projects. These tests have been examined from time to time in rate application hearings before the Board. However, the examination of each utility's economic feasibility tests has been on an individual basis without benefit of a common public review. A summary of these economic feasibility tests is contained in Appendix A.

Was Page 28. See Image [OEB:11L1W-0:31]

275

6.3 In the Discussion Paper, Board staff outlined what it perceived to be the weaknesses of the feasibility tests currently employed by Union, Consumers' and ICG.

276

1. The tests are based on a measure of feasibility which is too narrowly defined. Therefore these tests fail to recognize many of the additional benefits which accrue to an individual customer and to the area served by a new project, such as, savings on energy costs and major regional or more macroeconomic benefits.

277

2. Existing customers are serviced by facilities built at historical capital costs which have been significantly depreciated. These are significantly lower than current costs used in project assessment. A new project where current capital costs are used and where the annual costs are tested at a point in time when depreciation is low (5th year) is obviously at a disadvantage.

278

6.4 The first group of these are the "Five-Year, Rate of Return Tests".

Was Page 29. See Image [OEB:11L1W-0:32]

279

Five-Year, Rate of Return Tests

280

6.5 Five-year, rate of return tests are presently employed by Consumers' and ICG to demonstrate the economic feasibility of projects submitted to the Board in leave to construct applications. ICG also uses this methodology to assess all extensions involving more than 60 metres per customer. The test is based on the rate of return on investment to be achieved in the fifth year. The forecast of the annual incremental revenue from the project less its annual incremental gas costs, operation and maintenance expense, municipal and capital taxes, depreciation and income taxes, divided by the estimated cost less accumulated depreciation, equals the estimated rate of return on investment. This estimated rate of return is then compared with the Board approved rate of return on rate base for the distributor to determine if a particular project will be self-supporting. Generally, a project is considered economically feasible if the fifth-year rate of return on rate base equals or exceeds the Board approved rate of return on rate base.

281

6.6 The "five-year rule" has traditionally been considered a reasonable time frame since this is the period in which it was considered that the majority of the customer attachments would occur. It has also been considered by the

Was Page 30. See Image [OEB:11L1W-0:33]

282

Board as a reasonable time period for existing customers to subsidize new projects.

283

Participants' Positions on the Five-Year Rule

284

Consumers'

285

6.7 Consumers' indicated that they continue to use this method because of the Board's preference but the company considered that its Discounted Cash Flow (DCF) tests used to assess feasibility for other projects provide a better measure of the benefits and costs to existing customers from such projects.

6.8 Consumers' indicated that the five-year target for customer additions is an arbitrary and stringent target. it ignores load and revenue growth in the sixth and subsequent years when a surplus can occur which could create an overall surplus on a net present value basis. Therefore it does not account for the very long period of time in which the project may be producing greater than the allowable rate of return, which could offset the short subsidization period of up to four years. 286

ICG 287

6.9 ICG is of the view that its five-year rate of return test should be retained. ICG supports 288

Was Page 31. See Image [OEB:11L1W-0:34]

an expanded feasibility test which mirrors the rate of return approach by which the utilities are regulated. 289

Union 290

6.10 Union opposed the use of this test for evaluation of its system expansion projects. 291

Brant County Federation of Agriculture and Town of Kincardine 292

6.11 Both these Participants expressed concern with the five-year rate of return test as they felt that the five-year period should be extended. 293

Other Economic Feasibility Tests Presently In Use 294

6.12 Union and Consumers' use DCF analysis to assess the economic feasibility of most projects. DCF tests relate the net present value of the cash in-flows generated from a project to the net present value of its capital costs and other cash out-flows. The discounting of cash in flows and out-flows gives recognition to the time value of money (i.e. that a dollar spent today has a different value than a dollar spent in the future). 295

6.13 Most of the DCF tests employed by Union and Consumers' evaluate incremental costs and revenues of system expansion projects over their 296

Was Page 32. See Image [OEB:11L1W-0:35]

forecast economic life. At the Conference parties tended to agree that it becomes relatively insignificant to the end result if the DCF analysis is extended beyond twenty years. It was evident that, in general, incremental costs were used. 297

6.14 The three utilities confirmed that they use a five-year horizon for customer additions with the 298 revenues from these customers being assessed over the longer time horizon for the DCF test.

6.15 At present only Consumers' employs a formal risk analysis in the DCF feasibility test through the use of different time horizons for each class of customer to reflect the different risk that each imposes on the utility's system. 299

6.16 Union presently provides no such measure of risk in its DCF economic feasibility. However, in projects involving contract customers, the utility's risk exposure is eliminated by requiring that all capital costs be recovered over the contract period. Union indicated that it would not be opposed to performing sensitivity analyses on the factors incorporated in its tests to aid in establishing the risks involved. 300

Was Page 33. See Image [OEB:11L1W-0:36]

6.17 Union and Consumers' both agreed that the DCF methodology provides the best measure of the subsidy required from existing customers for a particular project. Each company noted, at the Conference, that they had refined the DCF methodology so that it could be easily adapted to assessing economic feasibility in the field. 301

Participants' Positions on Existing Tests of Economic Feasibility 302

Consumers' 303

6.18 Consumers' indicated a concern that neither of the tests it presently uses for financial feasibility allow for consideration of broad public interest benefits. 304

6.19 The company indicated that it supports changes which would allow these other beneficial factors to be considered. 305

ICG 306

6.20 ICG noted that its existing test is easily understood by its staff, the Board, and the municipalities as it follows the principles involved in rate of return on rate base determination. 307

Was Page 34. See Image [OEB:11L1W-0:37]

6.21 ICG submitted that the five-year test allows for easy measurement of cross-subsidization. 308

6.22 ICG noted that the DCF method can be subjective depending on the discount rate employed. It considered that the DCF methodology was difficult for its salesmen to perform. 309

Union 310

6.23 Union supported the position of Board staff that current economic feasibility tests, as presently 311 defined, produce a measure of feasibility which is too narrowly defined.

312

6.24 Union considered that storage and transmission expansion should be assessed separately and should not be included in the feasibility evaluation of the distribution projects that cause such expansion. Alternative Tests

313

6.25 During the Review, five alternative tests were presented. The Comparative Cost Test (Cost Test) and the Aggregate Customer Net Benefit Test (Benefit Test) were described in the Discussion Paper and Union Gas presented three tests of its own.

Was Page 35. See Image [OEB:11L1W-0:38]

314

6.26 As previously noted, the Board has concerns with economic feasibility tests, in particular how best to represent the appropriate benefits and costs. It is also concerned with the implications which flow from these tests as to the amount of subsidy required from existing customers. The five alternative tests address some of these concerns.

315

The Cost Test

316

6.27 The underlying assumption in the Cost Test is that it is unreasonable to expect a new project's costs to be fully recovered by rate schedules which are based, in part, on historic depreciated capital costs (see Appendix A for details of the test).

317

6.28 Feasibility for the Cost Test is thus determined by comparing a project's estimated fifth-year unit cost of service, excluding gas costs, to the utility's unit replacement cost of service. The project's fifth-year unit cost of service could then be adjusted by a load-risk factor (LRF) and/or a public interest factor (PIF). The LRF will adjust the project's unit cost upwards if its forecasted load is more uncertain or volatile than average. On the other hand, the PIF can be used to scale down a project's cost of service if it has specially meritorious public interest characteristics

Was Page 36. See Image [OEB:11L1W-0:39]

318

(e.g. geographical location, relative load concentration, security of supply).

319

6.29 A project will be acceptable if its adjusted unit cost of service is less than or equal to the utility's system-wide unit replacement cost of service.

320

Participants' Positions on the Cost Test

321

Consumers'

322

6.30 Consumers' submitted that the Cost Test has three major strengths: it recognizes the inequity in current tests with respect to the requirement that the cost of system expansion at current replacement costs should equate to the historical system average; it broadens the definition of feasibility to include total benefits and costs to society; and it will lead to a wider access to natural gas throughout the province.

6.31 Consumers' noted the weaknesses: the difficulty in calculating the PIF value beyond the point of valuing the energy savings to end use customers; and the revaluation of Existing System Unit Cost may require an extensive and costly study on an ongoing basis. 323

Was Page 37. See Image [OEB:11L1W-0:40]

6.32 Consumers' also criticized the use of the fifth-year reference point for cost of service comparison. 324

ICG 325

6.33 ICG noted that the PIF and the LRF adjustments are likely to be very subjective. The company indicated that attempting to quantify these factors may detract from the importance that should be given to the issues. 326

Union 327

6.34 Union indicated that an important strength of this test is that it addresses formally the public interest aspect of system expansion and in particular the problem that, as the utility system matures, the expansion of that system will be more costly. 328

6.35 Union submitted that the subjectivity involved and the difficulty in administering the test are its two major weaknesses. 329

Union's Alternatives to the Cost Test 330

6.36 Union presented two tests as alternatives to the Cost Test. At present, a system expansion project will pass Union's DCF test if its profitability index is greater than or equal to 331

Was Page 38. See Image [OEB:11L1W-0:41]

one. That is to say, a project will be accepted if it does not require a subsidy from Union's existing customers. 332

6.37 Union's first alternative would be to accept projects with profitability indices less than one, say 0.7 or greater. 333

6.38 The second alternative would employ historical costs instead of current costs in evaluating a system expansion project. A project would be accepted if its profitability index is greater than or equal to one. 334

The Board's Findings on the Cost Test (and on Union's Alternatives) 335

6.39 The Board recognizes that the Cost Test is a very explicit attempt to substitute "fairness" for economic feasibility as the principal criterion for project evaluation. However, the Board is of the view that public interest factors will vary from case to case and therefore cannot be assigned a numerical value as is proposed in the Cost Test. 336

6.40 The Board also notes that the test lacks two of the principal strengths of consumers' and Union's DCF tests. First, it does not take into account the time value of money. Second, it does not quantify the system expansion project's required subsidy and hence rate impact. 337

Was Page 39. See Image [OEB:11L1W-0:42]

6.41 The Board is further concerned that the calculation of the utilities' system replacement costs would be time consuming and imprecise. 338

6.42 In the opinion of the Board, Union's alternative tests are too narrow in scope to fully assess all the quantitative and qualitative costs and benefits of system expansion. 339

6.43 The second suggested test does not quantify the magnitude of the subsidy required from the utility's existing customers and has the same faults regarding public interest factors as the Cost Test itself. 340

The Benefit Test 341

6.44 The Benefit Test provides an analytical two stage cost-benefit framework for evaluating system expansion projects. The first stage is a DCF financial feasibility test. This test is similar to the DCF tests presently employed by Consumers' and Union with the notable exception that a social discount rate is used instead of the utility's cost of capital. 342

6.45 At the second stage, the customer benefits and costs of a system expansion project are compared. The benefits of system expansion are mainly the fuel cost savings of the new gas 343

Was Page 40. See Image [OEB:11L1W-0:43]

customers. The cost to the existing customers of proceeding with a system expansion project which does not satisfy the DCF analysis is an increase in their gas bills. Both the costs and the benefits of a project would be discounted by the social discount rate used in the DCF analysis. If the present value of the customer benefits is greater than or equal to the present value of the customer costs, then the project could be accepted. 344

Participants' Positions on the Benefits Test 345

Consumers' 346

6.46 Consumers' submitted that the major strength of the Benefit Test is that it considers the broad 347 effects beyond the pure economics of adding incremental projects to the system.

6.47 The company also asserted that the test provides a satisfactory indicator properly balancing factors over the life of the project. 348

6.48 Consumers' submitted that the main problem will be in determining and justifying the social discount rate. 349

6.49 Consumers' expressed concern that some customer benefits are not quantifiable. 350

Was Page 41. See Image [OEB:11L1W-0:44]

ICG 351

6.50 ICG submitted that the greatest strength of the Benefit Test is its consideration of societal benefits. The company submitted that the Benefit Test requires excessive judgement in several areas, particularly in establishing the appropriate social discount rate. 352

6.51 ICG also indicated that careful consideration should be given before adopting a test which is premised on the assumption that natural gas will continue to be priced favourably to alternate fuels. 353

Union 354

6.52 Union noted that a strength of the Benefit Test was the fact that it quantifies a wide range of public interest benefits that result from project implementation. The company also mentioned other strengths: the test is flexible enough to be applied to most types of system expansion; it employs the widely supported DCF methodology; and the test accounts for rate impacts that result from project evaluation. 355

6.53 The major weakness of the test, in Union's view, is its subjectivity. Considerable judgement will have to be exercised in the determination of several factors notably the social discount rate. 356

Was Page 42. See Image [OEB:11L1W-0:45]

6.54 Union proposed modifying the Benefit Test to address its concerns (see below). 357

The Board's Findings on the Benefits Test 358

6.55 The Board considers that the Benefit Test has some advantages: it employs a DCF financial feasibility test; it uses a social discount rate; and, it helps to quantify some of the major costs and benefits of the system expansion project. 359

6.56 Although the Board sees merit in this test, one of the other alternative tests suggested by Union is 360 considered to be preferable.

Union's Alternative to the Benefit Test 361

6.57 The alternative test proposed by Union to the Benefit Test is a three stage test which is a broader and more sophisticated version of the Benefit Test. Although the description employs Union's financial feasibility test, Union suggested that each utility could adopt the methodology it prefers for the first stage. 362

6.58 The first stage is Union's DCF financial feasibility test. It a project passes this test, it would be accepted, subject to the provision that it does not entail significant other social costs (e.g. environmental damage) that are not 363

Was Page 43. See Image [OEB:11L1W-0:46]

included in the feasibility calculation. If a project fails the first stage test, then it can proceed to the second stage for further evaluation. 364

6.59 At the second stage, all the quantifiable benefits not quantified in the first stage are quantified (e.g. energy cost savings to the new customers). 365

6.60 The subsidy required from the existing customers as well as other quantifiable social costs are calculated. The present values of all the above benefits and costs are determined using a social discount rate (the customers' cost of capital). 366

6.61 A sensitivity analyses on the key variables (e.g. social discount rate, gas prices, alternative fuel prices, inflation) is performed to assess the project's risk. If the analysis shows a project is relatively insensitive to major changes in the key variables, it is an added factor in favour of the project. A benefit to cost ratio is calculated by dividing the present value of the stage-two benefits by the present value of the stage-two costs. If the resulting ratio is greater than one, the project could be accepted subject to the provision that it does not entail significant other costs that still cannot be strictly quantified. 367

Was Page 44. See Image [OEB:11L1W-0:47]

6.62 At the third stage, the results of the first and second stages are considered together with any relevant unquantifiable costs or benefits and a judgement is made as to whether the project is in the public interest. If a project's second-stage benefit/cost ratio is greater than or equal to one, it may receive third-stage acceptance unless the resulting rise in rates (due to the subsidy) would cause a serious loss of the utility's existing load or it had significant unquantifiable social costs. 368

6.63 Alternatively, a project with a benefit/cost ratio less than one could be approved if it had significant unquantifiable social benefits. Participants' Positions on Union's Alternatives to the Benefits Test 369

Union 370

6.64 Union recommended that the Board adopt its three-stage methodology as a framework for system expansion decision-making. 371

Consumers' 372

6.65 Consumers' agreed that Union's Alternative to the Benefit Test is preferable to Union's other proposals. 373

Was Page 45. See Image [OEB:11L1W-0:48]

ICG 374

6.66 ICG conceded that this test seems to be an improvement over the Benefit Test. However, ICG stated that it did not endorse any of the Alternative Tests but preferred to modify its existing fifth-year rate of return test. It considered that the proper forum for deciding whether or not to change the current test is a public hearing involving an application, not at a technical conference. ICG also expressed the hope that any new guidelines adopted by the Board would be restricted to information requirements only and that the utilities would retain the right to present this information as they see fit. 375

The Board's Findings on Economic Feasibility Tests 376

6.67 The Board finds that of the tests currently in use by the utilities, the DCF analysis provides a superior measure of the subsidy required from existing customers for a particular project. 377

6.68 The Board directs all utilities to employ DCF analysis as part of its assessment of the feasibility of projects for system expansion. 378

6.69 The Board encourages the use of more formal risk measurement in the feasibility test and it 379

Was Page 46. See Image [OEB:11L1W-0:49]

would not discourage the use of sensitivity analyses of variables being regularly employed in the test. 380

6.70 The Board finds that incremental costs should be used in evaluating the feasibility of system expansion. 381

6.71 The Board will continue to assess the adequacy of the DCF analysis and any other tests used for project evaluation at the time of a utility's rate case hearing. 382

6.72 The Board finds that Union's three-stage test has considerable merit. The Board requires each utility to develop a three-stage process as outlined below to aid the Board in its determination of the public interest. 383

6.73 The first stage is a test based on a DCF analysis. 384

6.74 The second stage should be designed to quantify other public interest factors not considered at stage one. All quantifiable other public interest information as to costs and benefits should be provided at this stage. 385

6.75 The third stage should take into account all other relevant public interest factors plus the results from stage one and stage two. 386

Was Page 47. See Image [OEB:11L1W-0:50]

6.76 A project could, therefore, be accepted if it passed the DCF analysis of stage one and if the disadvantages and quantifiable costs from stages two and three do not disqualify it. If a project is not acceptable because it fails the DCF analysis or has significant other disadvantages, then stages two and three must be completed before the project can be said to be fully evaluated. 387

6.77 The Board is aware that each utility will continue to approve internally projects that lie within areas for which a franchise and a certificate of public convenience and necessity have been issued. At subsequent rate hearings the Board may assess the analyses employed before approving the inclusion in rate base of any specific project. 388

6.78 Any project brought before the Board for approval should be supported by all data used by the Applicant in reaching its conclusion that the project is viable. The utilities and other interested parties may use alternative analyses, but these and the results must be presented at the relevant hearing. The Board will continue to weigh the various benefits against the various disadvantages as it always has in reaching its decision in the public interest. 389

Was Page 48. See Image [OEB:11L1W-0:51]

6.79 The Board continues to hold the opinion that it is appropriate for existing customers to subsidize, through higher rates, financially non-sustaining extensions that are in the overall public interest if the subsidy does not cause an undue burden on any individual, group or class. 390

Was Page 49. See Image [OEB:11L1W-0:52]

7. THE ISSUE OF SUBSIDY 391

7.1 One of the major reasons for this Review is that much of the remaining expansion available to a utility and the public in a mature market area is generally uneconomic as judged by existing tests and a subsidy or a contribution in aid of construction is required. The preceding sections have dealt with changes that should be made in the determination of the subsidy or contribution required, and the public interest considerations. This section considers the potential expansion available and who should be required to make the contribution or provide the subsidy should it be required. 392

7.2 Each distributor provided a list of projects or municipalities that are currently not being served with natural gas but might be considered for system expansion. 393

Was Page 50. See Image [OEB:11L1W-0:53]

7.3 Union indicated that approximately 37 communities in its franchise area fall into this category and expansion into a sample of 13 of these communities would represent an $8.8 million dollar investment. 394

7.4 Consumers' review of possible expansion in or adjacent to its franchise areas indicated that there were a possible 43 projects that could be considered for its long term system expansion program. A sample of 13 of these projects represented about $21 million dollars of investment. 395

7.5 ICG indicated that there were 80 communities in its distribution area, with a customer potential of about 21,000, that presently do not have gas service. ICG stated that it would not consider expansion in gas service to any of these communities in the absence of a capital contribution. 396

Participants' Position on Subsidies 397

The City of Kitchener 398

7.6 Kitchener considered that economic feasibility as currently determined should be paramount in any decision relating to system expansion. it recommended that the Board should not take into account many of the public interest factors 399

Was Page 51. See Image [OEB:11L1W-0:54]

proposed by Board staff. Kitchener submitted that it is the responsibility of government to make decisions regarding uneconomic expansion. It stated that it makes no sense to impose the burden of this expansion on existing customers. 400

Consumers' 401

7.7 In the case of significant economic burden, Consumers' observed that it is neither fair nor logical for existing customers to bear the entire burden of subsidy for expansion. 402

7.8 Consumers' nevertheless supported the concept that areas of Ontario that are marginal with respect to gas service should be served if there are public interest benefits (including economic) beyond pure financial feasibility and where the extra cost to existing customers resulting from the extension will not be onerous. 403

7.9 Consumers' indicated that when broad public interest benefits accrue to Ontario, consideration should be given to the use of provincially administered funds for subsidizing system expansion. It was Consumers' view that a provincial fund similar to DSEP could be used to encourage expansion of service to customers who would not otherwise receive natural gas. 404

Was Page 52. See Image [OEB:11L1W-0:55]

7.10 Another alternative discussed by Consumers' would be to recover some of the cost from the local 405 community benefiting from the project. This could be accomplished through a municipal contribution-in-aid of construction or in the form of a time-limited surcharge on the rates charged to gas customers within the municipality.

7.11 Consumers' advocated that costs resulting from uneconomic expansion strictly defined should only flow through the utility's cost of service when the amounts involved will not impose a significant burden on existing customers. 406

ICG 407

7.12 With respect to subsidization, ICG proposed various alternatives. It noted that subsidization could be a provincial government responsibility. It discussed the possibility of subsidizing projects through the total utility cost of service and ultimately through rates but noted that there must be a limit to the burden imposed on existing customers. In addition ICG noted that contributions-in-aid of construction could be collected from the customers that would benefit from the gas service. 408

7.13 ICG asserted that the concept of a fair return to the utility's shareholders and its ability 409

Was Page 53. See Image [OEB:11L1W-0:56]

to raise capital at the lowest cost possible should not be compromised when considering the public interest aspects of system expansion. 410

Union 411

7.14 In terms of subsidization, Union stated that, in the absence of government funding, uneconomic areas could only be serviced through rate increases or contributions-in-aid of construction as there is no justification for shareholder subsidization because a higher rate of return would then be required. 412

Energy Probe 413

7.15 Energy Probe stated that extending service to marginal areas should only occur where existing customers are not asked to subsidize new ones. Energy Probe believes that government policy on this matter must be clear before decisions can be made regarding the subsidization of system expansion. It considered that it would be difficult to proceed without knowing what the provincial government deemed to be in the public interest. 414

7.16 Energy Probe asserted that the provincial government must not only determine whether or not expansion is appropriate but also whether natural gas is the preferred energy alternative. 415

Was Page 54. See Image [OEB:11L1W-0:57]

If the government perceives a public interest in taxpayers or existing customers subsidizing extension, 416 the subsidy should be explicitly initiated by government.

7.17 In Energy Probe's view the Board must have explicit policy direction from the government 417
regarding what constitutes the public interest before the Board incorporates broader public interest factors into the decision making.

Parry Sound Area Economic Development Commission 418

7.18 This group indicated that the government should determine the priority in which marginal areas 419
are to be served and that a government subsidy should be provided.

Deep River 420

7.19 This municipality indicated the importance to a community of having natural gas service and 421
stated that both the federal and provincial governments should encourage service of natural gas to small towns in Ontario by way of subsidies. It stated that it would not refuse to provide a contribution towards construction but that municipal funds for such projects would be difficult to raise.

Was Page 55. See Image [OEB:11L1W-0:58]

Public Interest Participants 422

7.20 This group stated that the policy of subsidization must be resolved by the government before any 423
matters concerning feasibility tests should be considered.

City of Toronto 424

7.21 This municipality opposed system expansion which would impose an undue burden on existing 425
customers.

Committee of Southwestern Ontario Municipalities 426

7.22 This group indicated that it is the role of federal and provincial governments to provide financial 427
assistance where needed for system expansion into areas not currently served.

7.23 It submitted that municipal contributions in aid of construction would be inappropriate as such 428
contributions would have implications on a municipality's financial integrity and would suggest the involvement of the Ontario Municipal Board.

The Board's Findings on Subsidy 429

7.24 As noted earlier, the Board considers that in general, the public interest is satisfied if 430

Was Page 56. See Image [OEB:11L1W-0:59]

the welfare of the public is enhanced without imposing an undue burden on any individual, group or class. 431

7.25 The Board has previously stated herein that the economic feasibility of a project should not be the sole criteria examined nor the determining factor in the approval process. 432

7.26 The economic feasibility tests currently employed by the utilities result in projects being accepted that require a degree of subsidy from existing customers. With the five-year rate of return test the project may require a subsidy from existing customers for the first four years. Similarly the DCF methodology may result in approval of a project which requires a subsidy from existing customers in its early years, with the subsidy being offset by the benefits in later years. The Board has, in the past, considered that subsidy as reasonable, recognizing that future benefits may offset the subsidy in later years. 433

7.27 The implication of accepting an economic test which has a broader definition of economic feasibility than that employed in the past is that the subsidy required may in general be greater than that which was deemed reasonable by the Board in the past. 434

Was Page 57. See Image [OEB:11L1W-0:60]

7.28 The Board notes that several projects that received DSEP funding did not meet the fifth year rate of return test. Nevertheless the Board accepted that the projects were in the public interest and approved these projects even though a subsidy would still be required from existing customers in the fifth year of the project. 435

7.29 The Board finds that a contribution-in-aid of construction should be required for those projects where the sole purpose is to supply gas into a new area and where the evaluation process demonstrates an undue burden on existing customers. 436

7.30 The Board would expect an agreement to be reached between the utility and the community regarding the contribution before an application is made to the Board. 437

7.31 In certain cases, the Board considers that special rates and/or loans by the utility to finance a contribution-in-aid of construction, may facilitate the expansion of the natural gas system. 438

7.32 A number of the participants strongly suggested that the provincial government encourage expansion of the natural gas system in Ontario by 439

Was Page 58. See Image [OEB:11L1W-0:61]

developing a program to fund uneconomic projects. The Board considers that, in addition to the methods of subsidy referred to above, some government support might be justified where the overall benefits to 440 the community as a whole warrant such action.

Completion of the Proceedings 441

7.33 The Board will issue a procedural order in future proceedings to adopt the Board's findings in this Report. 442

443

Dated at Toronto this 1st day of June, 1987.

<signed>
J.C. Butler
Vice-Chairman and
Presiding Member
<signed>
J.A. Dekort
Member
<signed>
M.A. Daub
Member

Was Page 59. See Image [OEB:11L1W-0:62]

Appendix A 444

Economic Feasibility Tests 445

Was Page 60. See Image [OEB:11L1W-0:63]

Economic Feasibility Tests: A Summary 446

Was Page 61. See Image [OEB:11L1W-0:64]

447

Was Page 62. See Image [OEB:11L1W-0:65]

Economic Feasibility Tests: 448

Details 449

A. Consumers' Gas Feasibility Cash Flow Test 450

Type Discounted Cash Flow (DCF) 451

Applicability - Large Volume Customers (340 10(3)m(3)/year+) Mains cost $50,000 + 452

Time Horizon Residential 50 years Small commercial and industrial 25 years Large volume 5 years 453
Interruptible 3 years

454

Revenue	Years 1-5:	estimated incremental revenues

(assuming today's rates) 455

Year 6+: 5th year estimate used 456

457

Gas Cost	Years 1-5:	estimated incremental gas costs

(assuming today's incremental 458
price of gas)

Year 6+: 5th year estimate used 459

Storage Cost Storage costs (average incremental) are included in gas cost estimate 460

461

O&M Costs	Years 1-5:	estimated incremental O&M costs

Year 6+: 5th year estimate 462

Was Page 63. See Image [OEB:11L1W-0:66]

Consumers' Gas 463
Feasibility Cash Flow Test (cont.)

464

Capital Cost	Years 1-5:	Budget average unit costs or field

estimates 465

Year 6+: 0 Salvage Value? 466

Overhead Cost Incremental Overhead cost relating to the system expansion program is capitalized and allocated to each project in proportion to the capital cost of mains 467

Discount Rate Marginal after tax cost of capital (M.A.T.C.C.) 468

Risk Adjustment see Time Horizon 469

Inflation Adjustment none 470

Required Rate of Return see Discount Rate 471

Taxes Incremental taxes are estimated 472

Feasibility Calculation A project is feasible if the cumulative after tax net present value of operating cash flows is greater than or equal to the net present value of capital expenditures. 473

Was Page 64. See Image [OEB:11L1W-0:67]

Consumers' Gas
Feasibility Cash Flow Test (cont.) 474

Calculation of Contribution in Aid of Construction Capital contribution required to make the project' net present value equal zero. 475

Was Page 65. See Image [OEB:11L1W-0:68]

B. Consumers' Gas Capital Requisition Test 476

Type DCF 477

Applicability Small system expansion projects 478

Time Horizon Same as CFT 479

Revenues Same as Cash Flow Test (CFT) 480

Gas Costs Same as CFT 481

Storage Costs Same as CFT 482

O&M Costs Same as CFT 483

Capital Costs Same as CFT 484

Overhead Costs Same as CFT 485

Discount Rate Same as CFT 486

Risk Adjustment See Time Horizon 487

Was Page 66. See Image [OEB:11L1W-0:69]

Consumers' Gas 488
Capital Requisition Test (cont.)

Required Rate of Return Marginal after tax cost of capital 489

Taxes Incremental municipal, capital and income taxes are estimated as a % of capital and miscellaneous costs 490

Feasibility Criteria A project is feasible if its 5th year annual revenues are greater than or equal to its 5th year annual costs (operating and maintenance, gas, capital and taxes). The fifth year annual costs also include a return on the estimated capitalized revenue short fall during the first four years. 491

Calculation of Contribution in Aid of Construction Capital contribution required to make 5th year annual cost equal to 5th year annual revenue. 492

Was Page 67. See Image [OEB:11L1W-0:70]

C. Consumers' Gas Short Main Extensions 493

Applicability Main extensions of 300 metres or less 494

Feasibility Criteria Approved if average main extension, exclusive of road crossings, is 18 metres or less 495

Was Page 68. See Image [OEB:11L1W-0:71]

D. Consumers' Gas Leave to Construct Test 496

Type 5th Year Rate of Return 497

Applicability Leave to Construct Applications 498

499

Time Horizon See Feasibility Criteria

Revenues Same as CFT 500

Gas Cost Same as CFT 501

Storage Cost Same as CFT 502

O&M costs Same as CFT 503

Capital Costs Same as CFT 504

Overhead Costs Same as CFT 505

Discount Rate Not applicable 506

Risk Adjustment None 507

Was Page 69. See Image [OEB:11L1W-0:72]

Consumers' Gas 508
Leave to Construct Test (cont.)

Required Rate of Return See Feasibility Criteria 509

Taxes Incremental taxes are estimated 510

Feasibility Criteria A project is feasible if its estimated 5th year rate of return [5th year annual incremental revenues less 5th year annual incremental gas costs, operating and maintenance expense, municipal and capital taxes, depreciation (an accounting value") and income taxes divided by estimated rate base (an "accounting value") equals the company's marginal regulatory cost of capital. 511

Calculation of Contribution in Aid of Construction Capital contribution necessary to make project feasible 512

Was Page 70. See Image [OEB:11L1W-0:73]

E. Consumers' Gas Upgrading or Replacing Existing Facilities 513

Type DCF if quantifiable 514

Applicability Capital projects to upgrade or replace existing facilities 515

Time Horizon Economic life of project 516

Revenues Incremental if applicable 517

Discount Rate Marginal cost of capital 518

Feasibility Critera Choose the minimum cost alternative. N.B.: Unquantified factors such as safety will be taken into consideration 519

Was Page 71. See Image [OEB:11L1W-0:74]

F. Union Gas General Service Test (GST) 520

Type DCF 521

Applicability Non-Contract customers 522

Time Horizon 20 years 523

Revenues	Years 1-5:	Estimated incremental distribution	524

revenues (assuming today's rates) 525

Year 6 +: 5th year estimate 526

Gas Costs	Years 1-5:	Incremental volumes per year x	527

current average cost of gas 528

Year 6 +: 5th year estimate used 529

Storage Cost Not included 530

O&M Cost	Years 1-5:	Number of customers added per year x	531

Union's average O&M costs 532

Year 6 +: 5th year estimate used 533

Capital Cost Project Specific estimate Salvage value not included 534

Was Page 72. See Image [OEB:11L1W-0:75]

Union Gas 535

General Service Test (GST) (cont.) 536

Overhead Cost Incremental 537

Discount Rate Board approved cost of capital (B.A.C.C.) 538

Risk Adjustment None 539

Inflation Adjustment None 540

Taxes Incremental income taxes are calculated Municipal taxes are estimated to be 1% of total capital expenditures. 541

Required Rate of Return See Discount Rate 542

Feasibility Criteria A project is feasible if the net present value of cash inflows divided by the net present value of capital costs is greater than or equal to one. 543

Calculation of Contribution in Aid of Construction Capital contribution necessary to make project feasible 544

Was Page 73. See Image [OEB:11L1W-0:76]

G. Union Gas Contract Customer Test 545

Type Pay Back 546

Applicability Contract customers 547

548

Time Horizon Contract length

Revenues Contract volumes x contract rate 549

Gas Costs Contract volumes x the current average cost of gas 550

Storage Costs Not included 551

O&M Costs Number of customers x average incremental operating cost of a contract customer 552

Capital Costs All incremental capital costs associated with supplying gas to customers 553

Overhead Costs See GST 554

Discount Rate Not applicable 555

Was Page 74. See Image [OEB:11L1W-0:77]

Union Gas 556
Contract Customer Test (cont.)

Risk Adjustment All risk borne by customer 557

Inflation Adjustment None 558

Required Rate of Return Board approved pre-tax cost of capital 559

Taxes Analysis conducted on a pre-tax basis 560

Feasibility Criteria A project is feasible if the payback period is less than or equal to the contract period. The payback period is: 561

F X = ---------- N-(RF) 562

where: 563

X = The number of years required to return the facilities investment plus a required rate of return on invested capital 564

N = Gross Margin (Revenue less cost of gas less other operating and maintenance costs) 565

R = Pre-tax rate of return on rate base 566

F = Facilities capital costs 567

Was Page 75. See Image [OEB:11L1W-0:78]

Union Gas 568
Contract Customer Test (cont.)

Calculation of Contribution in Aid of Contribution The contribution is: F-X where: YN X = ---------- 569
1+(YR)

F = Facilities Capital Costs 570
X = Union's contribution

Y = Contract term in years where Y cannot be greater than 3 N = Gross Margin R = Pre-tax rate of 571
return F-X = cannot be less than zero

Was Page 76. See Image [OEB:11L1W-0:79]

H. Union Gas Leave to Construct Test 572

Type DCF or 5th Year Rate of Return 573

Applicability Leave to Construct applications 574

Time Horizon Same as GST 575

576

Revenues	Years 1-5:	Estimated incremental distribution

revenues (assuming today's rates) 577

Year 6 +: 5th year estimate 578

Gas Costs Estimated volume per year x (current average cost of gas 579

Storage Costs Not included 580

O&M Costs Estimated number of customers per year x average O&M cost as approved in last rate 581 case; plus incremental compression fuel and operating expenses

Capital Costs Project specific estimate of transmission costs plus average distribution cost x number of new customers 582

Overhead Costs Incremental 583

Was Page 77. See Image [OEB:11L1W-0:80]

Union Gas 584
Leave to Construct Test (cont.)

Discount Rate Marginal Cost of Capital 585

Risk Adjustment Same as GST 586

Inflation Adjustment Same as GST 587

Required Rate of Return See Discount Rate 588

Taxes Same as GST 589

Feasibility Criteria Same as GST 590

Calculation of Contribution in Aid of Construction N.B. Unless there is one major customer for whom the line is being built, Union will not attempt to collect an aid to construct. 591

Was Page 78. See Image [OEB:11L1W-0:81]

I. Union Gas 592

Cost Reduction Test 593

Type DCF 594

Applicability Distribution main replacements, storage wells, compressors etc. 595

Time Horizon Economic Life 596

Revenues Incremental savings resulting from the capital expenditure 597

598

Gas Costs Not Applicable

Storage Costs Not Applicable 599

O&M costs All incremental expenses associated with project 600

Capital Costs Incremental capital costs plus salvage value 601

Overhead Costs Incremental 602

Discount Rate Marginal cost of capital 603

Was Page 79. See Image [OEB:11L1W-0:82]

Union Gas
Cost Reduction Test (cont.) 604

Risk Adjustment None 605

Inflation Adjustment Yes 606

Taxes Incremental income taxes are calculated. Municipal taxes are included if applicable. 607

Required Rate of Return See Discount Rate 608

Feasibility Criteria A project is feasible if the net present value of the savings associated with the capital project are greater than the net present value of the total project costs. 609

Where there are alternative ways of meeting a particular need the project alternative with the lowest revenue requirement, on a net present value basis, is considered the least cost alternative. 610

Was Page 80. See Image [OEB:11L1W-0:83]

J. ICG Earnings and Expenses Test 611

Type 5th Year Rate of Return 612

Applicability All projects which are not approved by the 60 metre rule 613

Time Horizon 5 Years 614

615

Revenues Estimated incremental revenues (assuming today's rates)

Gas Costs Estimated load x incremental gas costs 616

Storage Costs Incremental costs (Union's current rates) 617

O&M Costs Average incremental costs 618

Capital Costs Estimated incremental capital costs 619

Overhead Costs Incremental overhead costs are included 620

Discount Rate Not applicable - methodology does not discount cash flows 621

Was Page 81. See Image [OEB:11L1W-0:84]

ICG Earnings and Expenses Test (cont.) 622

Risk Adjustment See Feasibility Criteria 623

Inflation Adjustment None 624

Taxes General taxes = 0.88% of the investment in mains, regulator stations and service lines 625
Incremental income taxes are calculated

Required Rate of Return Board approved rate of return 626

Feasibility A project is feasible if its 5th year operating income (revenues minus operating costs minus income taxes) as a percentage of its 5th year rate base (90.6% of net plant investment) is greater than or equal to the Board approved rate of return. A higher rate of return is required for projects that serve industrial customers. 627

Calculation of Contribution in Aid of Construction .1274R -OI C= ------------- .0831 628

C = contribution required OI = operating income in 5th year without contribution R = 5th year rate base without contribution 629

Was Page 82. See Image [OEB:11L1W-0:85]

K. ICG 60 Metre Rule 630

Applicability Extensions up to 300 metres 631

Feasibility An extension averaging 30 metres per customer is automatically approved 632

An extension averaging 60 metres per customer is automatically approved if for every customer there is also one potential customer 633

Was Page 83. See Image [OEB:11L1W-0:86]

L. Comparative Cost Test 634

Type 5th Year Rate of Return 635

Applicability All distribution system expansion projects 636

Time Horizon 5 years 637

Revenue Not applicable 638

Gas Cost Not applicable 639

Storage Cost 5th year depreciated project specific cost 640

O&M Costs 5th year project specific cost 641

Capital Cost 5th year depreciated project specific cost 642

Overhead Cost ? 643

Discount Rate Not applicable 644

Risk Adjustment Load risk factor (measures relative certainty of load forecast by customer class) 645

Was Page 84. See Image [OEB:11L1W-0:87]

Comparative Cost Test (cont.) 646

Inflation Adjustment None 647

Required Rate of Return Board approved cost of capital 648

Taxes 5th year project specific taxes 649

Feasibility Criteria A project is feasible if: 650

SC x LNF ò EPC x LRF ----- PIF 651

where: 652

SC = existing system's depreciated (5th year) unit replacement cost 653

LNF = load normalization factor (Actual Load) ---------------- (Normalized Load) 654

EPC = expansion project's depreciated (5th year) unit cost 655

LRF = load risk factor 656

PIF = public interest factor (measures project's relative public interest merit, e.g., 1.0 to 1.5) 657

Was Page 85. See Image [OEB:11L1W-0:88]

M. Aggregate Customer Net Benefit Test 658

Type DCF 659

Applicability All distribution system expansion projects 660

Time Horizon Economic life of project 661

Revenue Not applicable 662

Gas Cost Incremental gas costs 663

Storage Cost Incremental storage cost 664

O&M Costs Incremental O&M costs 665

Capital Cost Incremental capital cost 666

Overhead Cost Incremental overhead cost 667

Discount Rate Project-specific, risk-adjusted, customer-oriented social discount rate 668

Risk Adjustment See Discount Rate and Required Rate of Return 669

Was Page 86. See Image [OEB:11L1W-0:89]

Aggregate Customer Net Benefit Test (cont.) 670

Inflation Adjustment Implicit in forecast of customer benefits of using gas over alternate fuels 671

Required Rate of Return The utility's project-specific, marginal cost of capital, reflecting the risk impact of the project from a shareholder's perspective, is incorporated in the capital recovery factor 672

Taxes Incremental taxes 673

Feasibility Criteria A project is feasible if the sum of the discounted life cycle marginal benefits to the new customers is greater than or equal to the sum of the discounted life cycle marginal costs to existing customers. 674

The marginal benefits are the value of customers' total fuel cost savings resulting from the ability to purchase natural gas instead of the next cheapest energy source (typically oil). The marginal costs are the incremental changes in the gas bills of the utility's existing customers. 675

Symbolically, 676

n	MB	n	Mc
ä --------	ò	ä	-------

677

i=0 (i + s)(i) i=0 (i + s)(i) where: 678

MB = the marginal benefits to the new customers MC = the marginal cost to the existing customers s = the social discount rate n = the project's economic life in years. 679