

E.B.O. 188

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

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.

BEFORE: G.A. Dominy
Presiding Member

R.M.R. Higgin
Member

J.B. Simon
Member

FINAL REPORT OF THE BOARD

January 30, 1998

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1. THE PROCEEDING

1.1 THE BACKGROUND

- 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.
- 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.
- 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.
- 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").

- 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.
- 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:
- 1.1 Should financial feasibility be the only determinant for expansion or should it include, apart from security of supply and safety:*
- (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.
- 1.1.8 An Interim Report 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").

- 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.
- 1.1.10 In January 1997, the second ADR Settlement Conference was held. This resulted in the submission of:
- ! 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;
 - ! 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”);
 - ! letters of comment from various parties on the ADR Agreement and Dissent Document; and
 - ! responses (dated July 25, 1997) to a set of Board clarification questions to the utilities.
- 1.1.11 The parties concurring with the ADR Agreement and those substantially supporting the Dissent Document are listed in Appendix A.
- 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 to this Report.
- 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.

1.1.14 The Board's comments and findings are structured as:

- ! The Portfolio Approach
- ! Common Methods for Financial Feasibility Analysis
- ! Customer Connection and Contribution Policies
- ! Environmental Planning Requirements for System Expansion
- ! Monitoring and Reporting Requirements

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.

1.2 INTERVENTIONS

1.2.1 The following parties intervened in the proceeding:

- ! Canadian Association of Energy Service Companies
- ! City of Kitchener
- ! Consumers' Association of Canada
- ! Energy Probe
- ! Federation of Northern Ontario Municipalities
- ! Green Energy Coalition
- ! Grenville-Wood
- ! The Heating, Ventilation, Air Conditioning Contractors Coalition Inc.
- ! Industrial Gas Users Association
- ! Municipal Electric Association
- ! Natural Resource Gas Limited
- ! Northwestern Ontario Municipal Association
- ! Ontario Coalition Against Poverty
- ! Ontario Federation of Agriculture
- ! Ontario Hydro
- ! Ontario Native Alliance
- ! Ontario Pipeline Landowners' Association
- ! Ottawa-Carleton Gas Purchase Consortium

- ! Pollution Probe
- ! Power Workers' Union
- ! TransAlta Energy Corporation
- ! TransCanada PipeLines Limited
- ! Woodland Hills Community Inc.

Late Interventions

- ! The British Columbia Ministry of Energy, Mines and Petroleum Resources
- ! Canadian Industry Program for Energy Conservation
- ! Ecological Services For Planning Inc.
- ! F & V Energy Co-operative Inc.
- ! StampGas Inc.

2. THE PORTFOLIO APPROACH

2.1 INTERIM REPORT CONCLUSIONS

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.*

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.*

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.*

- 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.*
- 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 better (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.*
- 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 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 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

2.2.1 The ADR Agreement proposed that each utility group all proposed new distribution customers and 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).

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:

- i. service lines off existing mains are included;
- ii. security of supply projects are not included; and
- iii. reinforcement costs have been normalized rather than using forecast actual costs.

2.3 BOARD’S COMMENTS AND FINDINGS

Investment Portfolio

2.3.1 The Board accepts the ADR Agreement proposal that each utility would group into one portfolio, 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.
- 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.
- 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.
- 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.
- 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).
- 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.

- 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.
- 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 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.

Rolling Project Portfolio

- 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).
- 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.
- 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.
- 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.

3. COMMON METHODS FOR FINANCIAL FEASIBILITY ANALYSIS

3.1 INTERIM REPORT CONCLUSIONS

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.*

3.2 POSITIONS OF THE PARTIES

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

(a) Customer Attachment Horizon

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.

(b) Customer Revenue Horizon

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.

(c) Discount Rate

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.

(d) Discounting

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 throughout the year will be mid-year discounted, as will revenue, gas related costs, and operating and maintenance expenditures.

(e) Operating and Maintenance Expenditures

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

(f) Gas Costs

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.

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.

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.

3.2.4 The Dissent Document proposed:

- ! a customer attachment horizon no longer than 5 years (unless there is a specific contract);
- ! 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;
- ! customer use volumes representing the best estimates of the gas consumption for new customers; and
- ! the inclusion of incremental costs associated with gas storage and TransCanada PipeLines Limited transmission.

3.3 BOARD'S COMMENTS AND FINDINGS

3.3.1 The Board notes that the utilities have undertaken to apply consistent business principles for the 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 and adopts this as part of the Guidelines in Appendix B.

3.3.3 The Board is concerned that a customer revenue horizon of 40 years will encourage inclusion of 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 costs for the transportation and storage of gas will add unnecessary complexity to the DCF calculations for distribution system expansion projects.
- 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 proposed 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.

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

4.1 INTERIM REPORT CONCLUSIONS

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.*

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.*

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.*

- 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.*

4.2 POSITIONS OF THE PARTIES

- 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.

- 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.

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

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

4.3 BOARD'S COMMENTS AND FINDINGS

- 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.

- 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.

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
- 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.

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.

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.

5. ENVIRONMENTAL PLANNING REQUIREMENTS FOR SYSTEM EXPANSION

5.1 INTERIM REPORT CONCLUSIONS

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.*

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 ("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.*

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.*

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.*

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.*

5.2 POSITIONS OF THE PARTIES

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 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 mitigating 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 Board's Interim Report because:

- i. the utilities have not yet developed common guidelines on how to conduct and document the evaluation of their route selection; and
- ii. according to the ADR Agreement, the utilities can select a route that will cause significant 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 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 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

5.3.1 The Board notes that a move to a portfolio planning and management approach may result in less 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.
- 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.
- 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.
- 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.

- 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.
- 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.
- 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.

6. MONITORING AND REPORTING REQUIREMENTS

6.1 INTERIM REPORT CONCLUSIONS

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.*

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:*

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

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.

- 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.*
- 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 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.*
- 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.*
- 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.*

6.2 POSITIONS OF THE PARTIES

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.

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.

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:

! 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;

! 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

! 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.

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

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

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

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.

6.3 BOARD'S COMMENTS AND FINDINGS

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

Rate Case Review

- 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.
- 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.
- 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.

- 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:
- ! impact of the Investment Portfolio cash flow on the test year revenue deficiency; and
 - ! the ratio of incremental revenues to costs in the test year and subsequent three years.
- 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.
- 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.
- 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.

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.

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.

Ongoing Monitoring and Reporting

6.3.11 The Board notes that the primary purposes of the Guidelines in Appendix B 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.

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 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.

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.

- 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.

- 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.

7. COMPLETION OF THE PROCEEDING AND COSTS

7.1 COMPLETION OF THE PROCEEDING

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 of this Report.

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.

7.2 COSTS

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.

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.

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.

DATED AT TORONTO January 30, 1998.

G.A. Dominy
Vice Chair and Presiding Member

R.M.R. Higgin
Member

J. B. Simon
Member