ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF AN Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing October 1, 2010;

AND IN THE MATTER OF a hearing on the Board's Own Motion.

BOOK OF AUTHORITIES

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EB-2006-0243

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline and ancillary facilities in the Township of Malahide, Municipality of Thames Centre and the Town of Aylmer.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Ken Quesnelle
Member

Cathy Spoel
Member

DECISION AND ORDER

Introduction

Natural Resource Gas Limited ("NRG") has filed an application with the Ontario Energy Board (the "Board") dated October 13, 2006, under section 90(1) of the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15. NRG has applied for an Order of the Board granting leave to construct approximately 28.5 kilometres of 6 inch diameter steel natural gas pipeline and ancillary facilities (the "Proposed Facilities").

The construction of the Proposed Facilities will allow NRG to meet the natural gas distribution requirements of an ethanol plant proposed by Integrated Grain Processors Co-operative Inc. ("IGPC"), to be located in Aylmer, Ontario, within NRG's franchise area.

Proposed Facilities

The Proposed Facilities will interconnect with facilities, to be constructed by Union Gas Limited, north of Highway 401 on Bradley Avenue where the NRG franchise area abuts the Union Gas Limited franchise area. The pipeline of approximately 28.5 km in length, runs in southeasterly direction and traverses sections of the Township of Malahide, the Municipality of Thames Centre and ends in the Town of Aylmer.

A map of the proposed natural gas pipeline route and the ethanol plant is attached as Schedule “A”, to this decision.

Proceeding

The Board held an oral hearing in this matter on December 18, 2006, at which four intervenors, the Integrated Grain Processors Co-operative (“IGPC”), Union Gas Limited (“Union”), the Municipality of Thames Centre and the County of Middlesex (“the Municipalities”), participated. All parties support the application. On January 19, 2007 the Board held an oral hearing in order to review the status of the contracts between NRG and IGPC. The Board reiterated its position that it wished to review the final executed contracts prior to rendering its decision.

On January 31, 2007, the Board received and reviewed two final executed contracts between IGPC and NRG - the Gas Delivery Contract (“GDC”), and the Pipeline Cost Recovery Agreement (“PCRA”).

Economics of the Proposed Facilities

An economic evaluation of the project was completed in accordance with the requirements of the Board’s Guidelines set out in the E.B.O. 188 report on Natural Gas Systems Expansion. The results indicate that the Proposed Facilities have a net present value of $8.5 million and without any capital contribution, the profitability index of the Proposed Facilities would be 0.55. To protect the ratepayers of NRG, a capital contribution of approximately $3.8 million is required from IGPC to achieve a profitability index of 1.0. The PCRA between NRG an IGPC provides for this capital contribution.

This project represents a significant net capital expenditure by NRG of approximately 5.3 million dollars. The GDC covers delivery of natural gas for a period of 7 years and corresponds to of the economic evaluation horizon that was used to calculate the $ 3.8 million capital contribution.

The GDC establishes the minimum volume of gas that IGPC is required to accept and pay for in any contract year as well as the price at which that gas is to be supplied. NRG has committed to developing a new rate for the customer to be included in its fiscal 2008 rate application which is anticipated to be filed with the Board in April, 2007.

Prior to the commencement of the delivery of gas pursuant to the GDC, the customer is required to provide a security deposit to NRG in the amount of one month's delivery using the appropriate rate at the commencement date. NRG is entitled to draw upon the security deposit in the event that IGPC does not pay the invoice within the time frame that is provided in this GDC.

The PCRA requires IGPC to provide an irrevocable delivery letter of credit in the amount of $5.3 million, which IGPC must maintain fro as long as it continues to receive service. This letter of credit will be reduced annually to an amount equal to the net book value of the assets of this project. This aspect of the PCRA will ensure that NRG can draw on this letter of credit in the event of either a default by IGPC or its ceasing operation prior to the assets are fully depreciated, thereby avoiding the potential for stranded assets. This protects NRG and its ratepayers.

Environmental

Based on the environmental report filed as Exhibit C, Schedule 3, NRG indicates that it is not expected that there will be any significant environmental impacts from the Proposed Facilities, as they will be constructed on existing road allowances. NRG also indicated that it will mitigate any such environmental impacts. There will, however be minor temporary impacts resulting from construction activities.

Landowner Issues

The Proposed Facilities will be constructed within existing road allowances. Accordingly no easements will be required except for temporary workspace. A list of abutting landowners is found at Exhibit C, Schedule 2 of NRG's application. NRG's evidence indicates that all affected landowners were made aware of the project both in their consultation and by way of the Boards Notice of this proceeding. There were no objections raised by landowners in this proceeding.

Board Finding

The Board is satisfied that the terms and conditions of the two agreements, the GDC and the PCRA, adequately protect the interests of NRG and its ratepayers against anticipated risks. In making its finding to grant the requested leave to construct, the Board is placing significant reliance on the terms and conditions of both the PCRA and GDC that protect the interest of NRG's ratepayers.

The Board finds that the Proposed Facilities are in the public interest and grants the requested leave to construct. The Board notes that this is a significant expansion of NRG's facilities and will increase its rate base by approximately 50 per cent

The Board appreciates that a project of this magnitude has not been without its complexities and appreciates the co-operation of all parties involved.

IT IS THEREFORE ORDERED THAT:

1. Natural Resources Gas Limited is granted leave pursuant to subsection 90 (1) of the *Ontario Energy Board Act, 1998* to construct approximately 28.5 kilometers of 6 inch natural gas pipeline and related facilities, commencing near the City of London, and running in southeasterly direction and traverses sections of the Township of Malahide, the Municipality of Thames Centre and ends in the Town of Aylmer.

2. The granting of leave is subject to the Conditions of Approval set forth in Appendix "B".

DATED at Toronto, 2007 February 02.

ONTARIO ENERGY BOARD

Original signed by

Gordon Kaiser
Signed on behalf of the panel

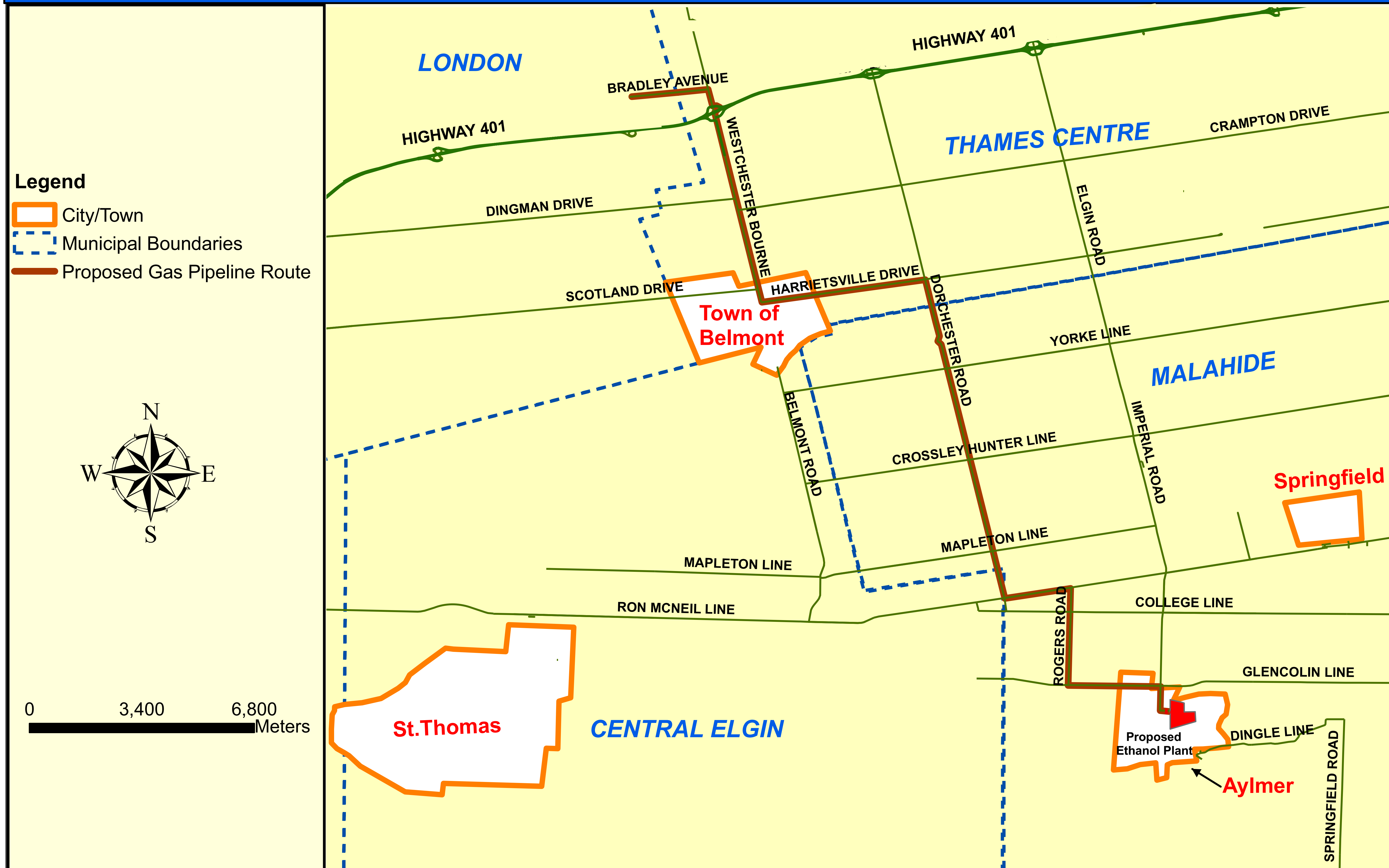
SCHEDULE "A"

to the Decision and Order

BOARD FILE NO. EB-2006-0243
February 2, 2007

Proposed NRG Ltd. Gas Pipeline Route

Proposed NRG Ltd. Gas Pipeline Route



SCHEDULE "B"

to the Decision and Order

BOARD FILE NO. EB-2006-0243
February 2, 2007

Conditions of Approval

Schedule “B”

CONDITIONS OF APPROVAL
EB-2006-0243

Natural Resources Gas Limited–Proposed Pipeline to IGPC Project

1 General Requirements

1.1 Natural Resources Gas Limited (NRG) shall construct the facilities and restore the land in accordance with its application and evidence, except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2007, unless construction has commenced prior to then.

1.3 Except as modified by this Order, NRG shall implement all the recommendations of the Environmental Study Report filed in the pre filed evidence, and all the recommendations and directives identified in the Ontario Pipeline Coordinating Committee (“OPCC”) review.

1.4 NRG shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, NRG shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Facilities Applications.

2.2 NRG shall designate a person as project engineer and shall provide the name of the individual to the Board’s designated representative. The project engineer will be responsible for the fulfilment of the Conditions of Approval on the construction site. NRG shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board’s Order being issued.

2.3 NRG shall give the Board's designated representative and the Chair of the OPCC ten days written notice, in advance of the commencement of the construction.

2.4 NRG shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 NRG shall file with the Board’s designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 NRG shall furnish the Board’s designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, NRG shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within eighteen months of the in-service date. NRG shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm NRG’s adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

3.4 Within fifteen months of the in-service date, NRG shall file with the Board a written Post Construction Financial Report. The Report shall indicate the actual capital costs of the project and shall explain all significant variances from the estimates filed with the Board.

4 Easement Agreements

4.1 NRG shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals and Contracts

5.1 NRG shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

5.2 NRG shall not, without the prior approval of the Board, consent to any alteration or amendment to the Gas Delivery Contract or the Pipeline Cost Recovery Agreement as those agreements were executed on January 31, 2007, where such alteration of amendment has or may have any material impact on NRG's ratepayers.

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

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1. THE PROCEEDING

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1.1 THE BACKGROUND

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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.

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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.

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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.

18

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").

Was page 2 19

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.

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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:

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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. 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

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1.1.14 The Board's comments and findings are structured as: 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 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.* 80

2.2 POSITIONS OF THE PARTIES 81

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). 82

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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. 83

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

<u>Investment Portfolio</u> 89

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 90 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

Was page 12

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. 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

3.3.5 The Board finds however that the methodology should include a standard test or measure to assess 134
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].

Was page 17 136

4. CUSTOMER CONNECTION AND CONTRIBUTION POLICIES

137

4.1 INTERIM REPORT CONCLUSIONS

138

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.*

139

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.*

140

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.*

141

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.*

Was page 18 142

4.2 POSITIONS OF THE PARTIES

143

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.

144

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.

145

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. 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

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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 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. 165

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. 166

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

Was page 23 168

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. 169

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. 170

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. 171

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 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. 173

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

Was page 24

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. 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

Was page 25

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. 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

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6. MONITORING AND REPORTING REQUIREMENTS

183

6.1 INTERIM REPORT CONCLUSIONS

184

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.*

185

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:*

186

- *ratepayers are protected from financially risky decisions on expansion by the utilities;*

187

- *the utilities make decisions on which projects should proceed in an even-handed manner;*

188

- *the cumulative impact on rates is not undue in any given year;*

189

- *the continued expansion of natural gas service is in the overall public interest; and*

190

- *the economic inefficiencies implicit in including projects with negative P.I.s do not outweigh the public interest benefits of the portfolio approach.*

191

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.*

Was page 28 192

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.*

193

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.* 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 29 200

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; 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

Rate Case Review 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

<u>Ongoing Monitoring and Reporting</u> 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.

226

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.

227

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.

Was page 33 228

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.

229

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.

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7. COMPLETION OF THE PROCEEDING AND COSTS

232

7.1 COMPLETION OF THE PROCEEDING

233

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.

234

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.

235

7.2 COSTS

236

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.

237

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.

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.

239

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

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APPENDIX A

Parties Concurring with the ADR Agreement 242

243
Board Staff
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

245
Canadian Industry Program for Energy Conservation*
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

246
* Letter of Comment Received

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

1998 248

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CONTENTS

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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

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Customer Connection Policies 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

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1. SYSTEM EXPANSION PORTFOLIOS

1.1 Investment Portfolio 272

Each of the utilities will group into a portfolio (the "Investment Portfolio") the costs and revenues 273
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.

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 276
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.

The utilities will calculate monthly the cumulative result of project-specific DCF analyses from the 277
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.

2. STANDARD TEST FOR FINANCIAL FEASIBILITY 278

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

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

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(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

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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

Was Appendix, page 6 322

(e) the rate impact of the Historic Year Investment Portfolio reflecting actual capital expenditures and customer related data.

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. <u>Financial Monitoring</u> 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 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: 330

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

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 the Ontario Pipeline Coordination Committee, how they were addressed, and reasons for any outstanding concerns; 333

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

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

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 PI of at least 1.0, the following will occur: 339

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

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

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

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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.

All provincial and local agency requirements (permits, licences) shall be obtained where necessary and the utilities shall apply their standard guidelines, drawings, and specifications. 353

6. DOCUMENTATION, RECORD KEEPING AND REPORTING 354

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. 355

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. 356

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. 357

The utilities shall file quarterly with the Board Secretary, the updated monthly Rolling Project Portfolio results immediately upon completing the calculations. 358

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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*

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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).

Note: Above is discounted, using mid-year discounting, over the customer revenue horizon. 363

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)*

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b) Annual Contributions

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

Note: Above is discounted to the beginning of year one over the customer addition horizon. 366

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 : <u>*[(Income Tax Rate) * (CCA Rate) * Annual Total Capital]*</u>

(CCA Rate + 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. <u>Discount Rate</u>

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

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2006-0243**	
VOLUME:	**MOTION HEARING**	
DATE:	**June 29, 2007**	
BEFORE:	**Gordon Kaiser**	**Presiding Member and Vice Chair**
	Ken Quesnelle	**Member**
	Cathy Spoel	**Member**

EB-2006-0243

THE ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline and ancillary facilities in the Township of Malahide, Municipality of Thames Centre and the Town of Aylmer.

Hearing held at 2300 Yonge Street, 25th Floor,
Toronto, Ontario, on Friday,
June 29, 2007, commencing at 8:32 a.m.

Motion Hearing

B E F O R E:

GORDON KAISER PRESIDING MEMBER and VICE CHAIR

KEN QUESNELLE MEMBER

CATHY SPOEL MEMBER

--- Upon resuming at 2:25 p.m.

MR. KAISER: Please be seated.

DECISION

MR. KAISER: The Board, this afternoon and this morning, has heard a motion filed yesterday on an urgent basis by Integrated Grain Processors Co-Operative, an Ontario cooperative, known as IGPC.

IGPC, together with its wholly owned subsidiary, IGPC Ethanol Inc., has completed the financing necessary to design, develop and build and operate an ethanol production in Aylmer, Ontario.

This motion was supported by affidavit evidence by Gordon Baird, a partner at McCarthy, Tetrault, counsel for the syndicate of lenders to IGPC; Martin Kovnats, a partner with the law firm of Aird & Berlis acting for the applicant; and Heather Adams, the chief administrative officer for the Corporation of the Town of Aylmer.

NRG, the utility that serves in this jurisdiction, was represented by counsel, but no witness was provided from the company or evidence filed.

This matter relates to an earlier decision of this Board on February 2nd, 2007, at which time NRG filed an application for a leave to construct approximately 28.5 kilometres of 6-inch-diameter steel pipe which was necessary to meet the natural gas distribution requirements of the proposed ethanol facility.

That leave to construct was granted by the Board, and in that decision the Board relied on two executed contracts, one known as the Gas Delivery Contract dated January 30th, 2007, the other the Pipeline Cost Recovery Agreement dated January 31st, 2007.

The gas delivery contract ensured revenues to the utility over the term of the agreement sufficient to ensure the Board that there would be no adverse consequences to ratepayers.

With respect to the Pipeline Cost Recovery Agreement, the Board found that to protect the ratepayers of NRG, a capital contribution of approximately $3.8 million was required from IGPC to achieve the required profitability. The PCRA agreement, or the pipeline recovery agreement, between NRG and IGPC provided for such a capital contribution.

The financing that has been put in place for this pipeline is provided by a number of sources. Approximately 11.9 million is from the federal government under its Ethanol Expansion Program administered by Natural Resources Canada. The project is also receiving a $14 million capital grant and ongoing operating grants from the Ontario Ethanol Growth Fund. The Co-Op, through its 840 farmer and rural community members, have invested over 45 million of their own funds in this project.

The dispute before us today relates to certain terms of the escrow arrangement that relate to those funds.

The financing which IGPC has arranged is subject to certain conditions in the escrow arrangement, which is being administered by Canada Trust.

One of the terms is that IGPC will contribute a combination of cash and value of at least $42.5 million, to be fully utilized before any advance is made under the credit facilities. IGPC intends to satisfy, in part, this contribution by assessing approximately 27.3 million of cash currently held in escrow, being part of the proceeds that have been raised from the sale of shares to the public.

The terms of this escrow agreement under the Co-Operatives Act provide that the escrow agreement cannot be amended without consent of members of IGPC. The escrow agreement provides, as it currently states, that all monies held in escrow must be returned to the subscribers of shares if, on or before June 30th, 2007, IGPC has not arranged sufficient funds to complete the ethanol facility and satisfied all conditions precedent to the first draw under the credit lines.

NRG has apparently refused to consent to an assignment contemplated in both of the agreements referred to, and, as a result, IGPC will not be able to satisfy the conditions precedent for the release of the escrow funds.

I want to turn next to the actual agreements. First, the question of whether the Board has jurisdiction, was raised by counsel for NRG.

Section 9.1 and 9.2 of the Pipeline Cost Recovery Agreement provides that:

> "In the event of any disputes arising between the parties regarding the subject matter of this

agreement, then the parties shall negotiate in good faith to resolve such matters. In the event the parties are unable to resolve a dispute, then either party may refer the matter to the OEB for resolution."

The Pipeline Recovery Agreement, which was the basis by which the funding was made available for the pipeline. I referred you to the Board's decision with respect to the aid of construction that was necessary and mandated by this Board in order to allow the leave to construct to be granted. That agreement contains certain terms and conditions, one of which was in 11.2(d):

"Provide this agreement will not be assigned without the prior written consent of the other party, such consent not to be unreasonably withheld. For greater certainty, an assignment by way of security to the customers' lenders shall be considered reasonable."

A similar section exists in the Gas Delivery Contract, also approved by the Board as part of the February 2nd decision. There section 7.4 says:

"This contract shall be binding on and enure to the benefit of the parties hereto and their respective successors and assigns, shall not be assigned or be assignable by the customer without the prior written consent of the utility. The utility agrees that such consent shall not be unreasonably withheld. For greater certainty, an assignment by way of security to the customers' lenders shall be considered reasonable."

We have heard evidence that the assignment in the form contemplated by the applicant has been in the hands of NRG's lawyers for over a month. To date, NRG has apparently refused to execute that consent to assignment.

This Board believes it has jurisdiction to enforce the two contracts before us. Section 42(3) of the Ontario Energy Board Act provides that:

"Upon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sales service."

What we have are two linked agreements. One is a Gas Distribution Agreement in favour of the applicant. The other is a Pipeline Cost Recovery Agreement by which the applicant has agreed and NRG has accepted certain funding which will make the pipeline viable.

While we may or may not have jurisdiction over an ethanol plant, the Board certainly has jurisdiction over this pipeline and has rendered a decision with respect to it; namely, a leave to construct, and has approved the very funding that is at issue.

It is now apparent this funding will not flow through and the transaction cannot be completed unless the requested consent is executed in the form requested by the applicant.

There is no basis in this record to conclude that a refusal to execute the consent is reasonable. The agreement specifically contemplated and the parties agreed that a consent would be executed to the benefit of the company's lenders and, as such, would be considered reasonable.

We see no basis for this refusal and hereby order NRG to execute the consent in the form provided by the applicant.

Objection has been made by counsel for NRG as to the lack of notice. The Board's rules in section 7 clearly provide that the Board can abridge time. That is section 7.01 and 7.2, and we have done so. The urgency of the matter is clear.

In conclusion, we should add that various parties to this proceeding, include the Town of Aylmer as well as IGPC, have invested substantial sums in the expectation that this contract would proceed and this plant would be built. We are aware, from the main case, that the economic base of the Town of Aylmer is disintegrating, as a result of the problems in the tobacco industry. It was the expectation of all parties as well as the Board’s that the parties would proceed expeditiously to develop this facility within the expected timelines. As stated, we see no reason for the refusal by NRG to execute the requested agreement. It was clearly provided for in the contracts which are binding on NRG and subject to the jurisdiction of this Board.

That completes the Board's rulings with respect to the consent.

We have a collateral matter. There is a second agreement before us that is unexecuted, and to which a dispute arises. That is called the bundled T service receipt contract, which is Exhibit J1.5.

The evidence before us suggests that this is a standard form agreement, and not unique to this particular proceeding. We also note, and this is of some moment, that the contract to which the parties have agreed and executed namely J1.3, the Gas Delivery Agreement, specifically contemplates the bundled direct purchase delivery. That is set out in Schedule A, section 4.

This, again, is a service agreement, an agreement to provide service which the Board has clear jurisdiction over. The Board orders NRG to provide the service contemplated in that agreement.

That completes the Board's rulings with respect to the second agreement at issue.

With respect to costs and administrative penalties, we have heard certain submissions from counsel for the applicant. On those, we intend to reserve.

That completes the Board's ruling in this matter.

Any questions?

MR. THACKER: Do you want to hear submissions from me on costs?

MR. KAISER: Yes.

Please go ahead.

SUBMISSIONS BY MR. THACKER:

MR. THACKER: I guess I would submit that in the nature and manner in which this matter proceeded was served on short notice, and the manner in which the record was a bit of a moving target, there ought to be no order as to costs. We have done our best to respond under very trying circumstances. The evidentiary record was thin, and indeed it was fundamentally inadequate as it was served even on the abridged notice period. It was coopered-up throughout the proceeding and we have objected to the manner in which that was done, but it would be compounding unfairness to order costs against my client. That would be my submission.

MR. KAISER: Thank you, Mr. Thacker.

MR. THACKER: There should be no order as to costs.

MR. KAISER: Any submissions on costs, Mr. O'Leary?

MR. O'LEARY: Yes. Mr. Chair, I would be very brief in that regard.

SUBMISSIONS BY MR. O'LEARY:

Before I get to that, there is one question we have in respect to your order. That was in the draft we provided, we were looking for a specific time today by which time the agreements would be executed, because if it does not occur today, then this deal is in jeopardy. So we're wondering if you are in a position now to amend your order to require that it be executed forthwith and no later than 3 o'clock.

MR. KAISER: Well, let's make it 4:00. That gives Mr. Thacker some time to contact his client.

MR. O'LEARY: Yes. And in respect of costs, sir, I will not repeat my comments earlier, but I ask you to consider the record and the pattern of conduct exhibited by NRG, and in particular Mr. Bristoll, and the fact that we're here today and the costs have been incurred by the town, not only in respect to this litigation but in all of the attempts that it has made through its counsel to get NRG's attention to deal with these documents and to sign them, knowing that they have, as a utility, an obligation to execute these documents.

We submit that it is an appropriate time to send a message to this utility that it needs to wake up and start to run itself in accordance with the appropriate standards as a good utility.

MR. KAISER: Thank you. Mr. Mayor, any submissions on costs?

MR. HABKIRK: Well, we would certainly like to see them -- we would certainly like to see those costs come from NRG. In regards to the stumbling blocks, the time we have invested as a community, the assessment base that we may lose in the future by people hearing such things as this, but the fact of the matter is we have invested a lot of time and effort and legal fees to make sure that this deal came about for the benefit of our community and our residents. So, yes.

MR. KAISER: Thank you, sir. Anything further, Mr. O'Leary?

MR. O'LEARY: No, sir.

MR. KAISER: Thank you, gentlemen, ladies.

MR. THACKER: Sorry, I should have asked this earlier. Are you approving the order in the manner in which it was delivered, or is the order going to be driven by your reasons as read?

MR. KAISER: The latter.

MR. THACKER: Thank you.

--- Whereupon hearing concluded at 2:45 p.m.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2006-0243

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct a natural gas pipeline and ancillary facilities in the Township of Malahide, Municipality of Thames Centre and the Town of Aylmer.

AND IN THE MATTER OF Section 19 of the *Ontario Energy Board Act, 1998.*

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Ken Quesnelle
Member

Cathy Spoel
Member

DECISION AND ORDER

On October 13, 2006 Natural Resource Gas Limited ("NRG") applied to the Ontario Energy Board under section 90(1) of the *Ontario Energy Board Act, 1998* for an Order granting leave to construct approximately 28.5 kilometers of natural gas pipeline. The pipeline is to be located in Township of Malahide, the Municipality of Thames Centre and the Town of Aylmer and will interconnect with facilities to be constructed by Union Gas Limited ("Union Gas") as shown in the map attached as Appendix A.

The pipeline will allow NRG to meet the natural gas distribution requirements of an ethanol plant proposed by Integrated Grain Processors Co-operative Inc. ("IGPC"), to be located in Aylmer, Ontario, within NRG's franchise area.

The Board held a hearing in this matter on December 18, 2006. On January 31, 2007, the Board received and reviewed two final executed contracts between IGPC and NRG - the Gas Delivery Contract ("GDC"), and the Pipeline Cost Recovery Agreement ("PCRA"). On February 2, 2007 the Board issued its Decision and Order (as amended December 28, 2007) approving the two agreements and granting NRG leave to construct the pipeline subject to certain conditions. The conditions of approval contained in the Board's Leave to Construct Decision are reproduced in Schedule A to this Decision.

The Motion

On February 8, 2008 the Board received correspondence from IGPC relating to construction delays by NRG and disputes regarding certain provisions of the Pipeline Cost Recovery Agreement ("PCRA"). On February 12, 2008 NRG filed a letter in response to IGPC's claims.

On February 15, 2008 IGPC filed a Notice of Motion with the Board seeking Orders establishing a timetable for the completion of the pipeline by NRG, an Order requiring NRG to pay all third party suppliers on a timely basis and an Order confirming that IGPC was required to provide NRG a Delivery Letter of Credit in the amount of $5.3 million.

This is the third hearing the Board has held with respect to this project, two of which have been on an emergency basis. The Board is fully aware of the importance of this project to the community. The Board is also aware of the substantial financial commitment by members of the Co-operative, the Federal government and the Provincial government.

In an attempt to resolve the dispute quickly, the Board issued an Order on February 22, 2008 directing both NRG and IGPC to attend before the Board at an oral hearing on February 28, 2008 at the Old Town Hall in Alymer, Ontario. Both parties were also ordered to produce company witnesses capable of answering questions from the Board regarding the alleged delays in construction, disputes regarding the Delivery Letter of Credit required under the PCRA and the non-payment of suppliers.

The Issues:

At the hearing in Aylmer on February 28, 2008 both NRG and IGPC produced company witnesses, as ordered, to answer questions from the Board. The Town of Aylmer was also represented by counsel and participated throughout. The Mayor of Aylmer and various elected officials were also in attendance.

It became apparent that there were six issues in dispute:

1. IGPC's failure to deliver Letters of Credit;
2. The proper amount of the Letter of Credit;
3. Payments by NRG to Union Gas regarding costs related to the pipeline construction;
4. Advance payments by NRG to Lakeside Process Controls Ltd.
5. IGPC's failure to pay NRG for various third party invoices ; and
6. Allegations regarding delay in the pipeline construction.

At the hearing in Aylmer, the parties agreed that the issues with respect to payments by NRG to Union Gas to underwrite the costs borne by Union Gas for the Union part of the pipeline construction could be best dealt with by having IGPC deal with Union Gas directly. The same approach was taken with respect to the advance payments required of NRG to Lakeside Process Controls Ltd. Accordingly, it was not necessary for the Board to deal with these two issues.

The Board's Decision and the parties' agreement to this procedure are set out in the Board's oral decision in the Transcript of February 28th at page 138 which is reproduced at Schedule B of this Decision

A related issue concerned allegations by NRG that IGPC had failed to pay NRG invoices. The parties agreed that they would resolve this dispute outside of this process and that any failure to resolve this dispute would not be a basis for delaying the construction of the pipeline.

This left two issues. The first was a determination of the proper amount of the Letter of Credit. To be provided by IGPC to NRG. The second was an agreed upon schedule for delivery of the Letter of Credit and undertaking certain steps in the construction process. Each of these matters is considered below.

The Amount of the Letter of Credit:

The cost NRG will incur in constructing the pipeline is approximately $9.1 million of which approximately $3.8 million is financed by a payment by IGPC to NRG called an Aid to Construction and a Delivery Letter of Credit by IGPC to NRG in the amount of $5.3 million. The Board in its Decision of February 2, 2007 accepted the estimate of $5.3 million with respect to the Letter of Credit as follows:

> "The PCRA requires IGPC to provide an irrevocable delivery letter of credit in the amount of $5.3 million, which IGPC must maintain for as long as it continues to receive service. This letter of credit will be reduced annually to an amount equal to the net book value of the assets of this project. This aspect of the PCRA will ensure that NRG can draw on this letter of credit in the event of either a default by IGPC or its ceasing operation prior to the assets are fully depreciated, thereby avoiding the potential for stranded assets. This protects NRG and its ratepayers."

NRG argued that this amount now appears to be insufficient and fails to reflect seven additional categories of costs. The first four costs are set out below together with the estimated annual costs.

M9 Delivery Costs	$422, 217
O & M Expense	$ 50,000
Capital Tax	$ 25,935
Property Taxes	$ 58,405

NRG states that these are annual costs that will be incurred during each of the seven years of the contract, regardless of whether or not IGPC is still a customer of NRG

At the hearing in Aylmer, NRG and IGPC agreed on the procedure to resolve the dispute with respect to these costs. Each of the parties will make written submissions. The Board will make a decision and that decision will be binding on the parties. This Decision is set out in the Transcript of February 28th at page 140 (see Schedule "B").

There are three additional costs which NRG claims are not reflected in the $5.3 million Delivery Letter of Credit. First, there is the cost of decommissioning the pipe in the event that the ethanol plant closes. Secondly, there is a potential income tax liability in the event NRG has to draw down on the Delivery Letter of Credit. Thirdly there is a break out fee or penalty that NRG would incur if as a result of the ethanol plant closing NRG is required to repay its loan to the bank earlier than contemplated under the existing loan agreement. Those three issues were decided by the Board in its oral decision of February 28th and are recorded in the Transcript at pages 141 and 142 (see Schedule "B").

Amendments to the Leave to Construct

Disputes in this proceeding arose as to whether NRG was delaying certain aspects of the construction. NRG in response indicated that it had not received the Delivery Letter of Credit. At the hearing, the parties agreed to a schedule that sets out mutual obligations and the timing of certain events. They have agreed that this Schedule will be added to and form part of the existing Leave to Construct Decision and that in the event of non-compliance, either party may apply to the Board for termination of that Leave to Construct Decision. In the event of termination, it would be open to other parties to apply for a leave to construct for this facility.

The wording of this new condition in the Leave to Construct Decision is attached to this Decision as Schedule C. It will form a new paragraph 6 in the Conditions of Approval, reproduced in Schedule A of this Decision.

IT IS THEREFORE ORDERED THAT:

1. The Board's Decision granting Leave to Construct the natural gas pipeline dated February 2, 2007, as amended on December 28, 2007 is hereby amended, on consent of Natural Resource Gas Limited and Integrated Grain Processors Co-operative Inc., by adding the additional conditions set out in Schedule "C" of this Decision;

DATED at Toronto, March 4, 2008

Ontario Energy Board

Original Signed By

Gordon Kaiser
Signed on behalf of the panel

Schedule "C"

Board File Number (EB-2006-0243)
March 4, 2008

Additional Condition of Approval
[to be added to the Conditions of Approval (see Schedule A to this Decision and Order) attached to the Board Decision and Order granting Natural Resources Gas Limited leave to Construct natural gas pipeline [February 7, 2007 as amended on December 28, 2007]

6 <u>Mutual Convenants</u>

6.1 NRG and IGPC agree that the schedule ("the Schedule") attached hereto will be adhered to in accordance with its terms and at the times set forth therein by the appropriate party and that the Leave to Construct is contingent upon such compliance by the parties of each aspect of the Schedule.

6.2 This condition is not effective as against Union Gas. Any delay by Union Gas of a task identified by Union Gas shall not be a basis for alleging non-compliance of breach of the Schedule by NRG, provided that both NRG and IGPC take all necessary steps to enable Union Gas to perform its tasks in accordance with the Schedule. If there is a delay in the Schedule by reason of a delay by Union Gas and the parties are unable to agree to an amendment of the Schedule, either NRG and IGPC may apply to the Board for a resolution thereof.

6.3 Upon an alleged failure to comply with the Schedule, either party may apply to the Board for such order or orders as are appropriate, including a termination of the Leave to Construct and such further or other relief as the Board deems appropriate for the circumstances.

the "Schedule"
attachment to Schedule C - "Conditions of Approval"

		Feb.				March					April				May				June					July				August				Comments
	Description of Activity	4	11	18	25	3	10	17	24	31	7	14	21	28	5	12	19	26	2	9	16	23	30	7	14	21	28	4	11	18	25	Week Commencing
	Union Gas Related Activities																															
1	Execute Indemnity by IGPC (parent) and Union Gas																															Completed Feb. 13, 2008
2	IGPC (parent) indemnity to be terminated by Union Gas by way of execution of the M-9 Agreement																															Indemnity terminates upon execution of the M-9 Agreement
3	IGPC (parent) Pays Union Gas Aid-to-Construct instalment payment of $200,000																															IGPC paid Union Feb. 13, 2008
4	IGPC (parent) provides $500,000 as balance of Aid-to-Construct and For Financial Assurance for Union Gas facilities																															
5	NRG to provide Union Gas with land requirements for NRG facilities at the point of Custody transfer.																															Union requires information to finalize details of purchase.
6	Union Gas and NRG to enter definitive agreement regarding ownership/leasing arrangements. Confirmation of arrangement to be provided to IGPC.																															
7	Union Gas enters agreement to secure property for Custody Transfer Station and NRG																															
	Union to provide M-9 Agreement (Draft)																															
8	M-9 Agreement between NRG and Union Gas to be executed -																															
9	Union Gas to return financial assurance to IGPC upon entering M-9 Agreement with NRG.																															M-9 Agreement to be entered by March 31, 2008.
10	Union Gas to finalize Design of Station																															
11	Union Gas Procurement of Material																															Union to attempt to secure rush delivery
12	Union Gas Construction																															
13	Union Gas Commissioning																															Union Gas - willing to work to try and improve date
14																																
15																																
16	**Lakeside Controls - Customer Meter Station for Ethanol Facility**																															
17	Receipt of Quote 1 by NRG																															Received by NRG January 25, 2008
18	Receipt of Quote by IPGC																															Received by IGPC from NRG on January 31, 2008
19	Receipt of Quote 2 - by NRG																															Received Feb. 11, 2008
20	NRG informs IGPC of 2nd Quote on Feb. 11, 2008																															First payment by IGPC to Lakeside Control $78,495.73 plus financial assurance of $313,982.94
21	Progress Payment #1 by IGPC to Lakeside Control																															
22	Progress Payment #2 by IGPC to Lakeside Control																															
23	Progress Payment #3 by IGPC to Lakeside Control																															

		Feb.				March					April				May				June					July				August				Comments
	Description of Activity	4	11	18	25	3	10	17	24	31	7	14	21	28	5	12	19	26	2	9	16	23	30	7	14	21	28	4	11	18	25	Week Commencing
24	Progress Payment #4 by IGPC to Lakeside Control																															
25	Progress Payment #5 by IGPC to Lakeside Control																															
26	Delivery of Station Equipment																															
27	Installation																															
28	Commissioning																															Tentative commissioning date.
29																																
30	NRG																															
31	Finalize Pipeline Construction Tender Package																															Package to be complete by Feb. 19, 2008
32	NRG Issued Construction Tender Package to Seven Contractors identified by NRG to IGPC																															Package to be sent out Feb. 19, 2008
33	Receipt of Bid Confirmation from contractors by NRG																															Feb. 22, 2008
34	NRG to provide contractor responses to bid confirmation to IGPC																															
35	Contractors Prepare Bid Submissions																															March 5, 2008 Bid Return Date
36	Contractors submit bids to NRG - IGPC and Design Engineer to be present for receipt and opening of bids.																															March 5, 2008 Bid Return Date
37	NRG to provide information regarding tenders to IGPC and a recommendation of preferred contractor.																															
	IGPC to provide input and consent to selection of the construction contractor																															
38	NRG to provide the the Revised Aid-to-Construct and information to support the calculation.																															Revised Aid to Construct Calculation to be provided by noon March 10, 2008 - *may require 2 or 3 extra days*
39	NRG and IGPC to confirm agreement on form of Delivery Letter of Credit.																															
40	IGPC to pay balance of Revised Estimate Aid to-Construct and Provide Delivery Letter of Credit of approximately $5,300,000 to NRG																															This is to occur at the same time as NRG enters construction Agreement with Contractor. This will happen through an escrow arrangement to occur at the same time as the Delivery Letter of Credit is provided and Balance of Revised Aid-to-Construct is paid.
41	NRG to execute Construction Agreement with successful Contractor																															This is to occur at the same time that IGPC provides balance of Aid-to-Construct and Delivery Letter of Credit. This will happen through escrow arrangements to coincide with execution of construction agreement.
42	NRG to confirm commitment of lender for completion of construction																															*may require 2 or 3 extra days*
	Banks for IGPC and NRG to meet to finalize LC wording																															*dependent upon schedule of bankers*
43	NRG to finalize financing for balance of construction project with Bank and/or acceptable equity contribution.																															NRG to provide written confirmation of financing to OEB and IGPC.

		Feb.				March					April				May				June					July				August				Comments
	Description of Activity	4	11	18	25	3	10	17	24	31	7	14	21	28	5	12	19	26	2	9	16	23	30	7	14	21	28	4	11	18	25	Week Commencing
44	Retain Project Manager, Construction Manager and Quality Assurance Inspectors for overseeing pipeline contractor.																															
45	Retain Non-Destructive Testing Company																															
46	Ensure all permits are secured																															
47	Mobilize Construction Forces																															
48	Pick up the Pipe and deliver to site construction yard																															*pick up to be arranged between contractor and Lakeside Steel as required by contractor*
49	Pipeline Construction																															Pipeline contractor to be have pipeline complete by June 17, 2008 - *date to be confirmed by IGPC by week of 10th of March.*
50	Non-Destructive Testing - Ongoing with pipeline construction - to be arranged by Construction Manager.																															Pipeline contractor to be have pipeline complete by June 17, 2008 - *see note 49*
51	Clean Up/Demobilization																															
52	Hydrotesting																															
53	Dewatering																															Pipeline contractor to be have pipeline complete by June 17, 2008
54	NRG to provide commissiong plan and schedule																															Commissioning plan to be prepared and June 16, 2008
	Commissioning of pipeline - contingent upon IGPC, Union and Lakeside in addition to pipeline contractor																															Pipeline commission is dependent upon completion of Union Gas work. Commissioning of pipeline to occur within 5 days of completion of Union Gas commissioning.
55	In-Service Date of Pipeline - *IGPC to notify*																															Contingent upon Union Gas - within 5 Business days of Union Gas
56																																
57	**Other:**																															
58	IGPC paid Lakeside Steel for Pipe																															IGPC paid $952,410 for pipe to Lakeside Steel on November 9, 2007
59	IGPC provides security deposit to NRG as provided for in the Gas Delivery Contract.																															Amount of Security Deposit is $221,586.72 as provided by Part 10 of the Gas Delivery Contract
	Substantial Completion of Ethanol Facility																															
60	IGPC Delivery of Notice under Bundled T Contract regarding commencement of Delivery of Gas.																															To be further advised.
61	NRG to provide any *required* notice for upstream transportation of gas. *Dependent upon notice by IGPC to NRG*																															IGPC to provide notice and then NRG to forthwith make any arrangements upstream as required
62	Union Gas - Preparation of Actual Costs																															
63	Calculate Actual Aid-to-Construct																															To be completed within 5 Business Days of Union Gas providing actual numbers. *Contingent upon completion, Union Gas compliance & receipt of final invoices from contractor(s)*

	Description of Activity	Feb.				March					April				May				June					July				August				Comments
		4	11	18	25	3	10	17	24	31	7	14	21	28	5	12	19	26	2	9	16	23	30	7	14	21	28	4	11	18	25	Week Commencing
64	Reconciliation payment as a result of determination of Actual Aid-to-Construct																															Payment due after calculation, *as per PCRA*
65	Ethanol Facility Requires Gas for Testing and Commissioning																															

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2010-0018

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing October 1, 2010.

BEFORE: Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

DECISION AND ORDER

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated February 10, 2010 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2011 fiscal year, commencing October 1, 2010.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 7,000 customers, with its service territory stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce to Clear Creek.

In its pre-filed evidence NRG claimed a revenue deficiency of $462,417 for the 2011 Test Year. If the application were to be approved as filed, a typical residential customer would experience an annual increase of $22.60 (or 5.05%) to the delivery portion of the bill.

The Board issued a Notice of Application dated March 1, 2010. The Town of Aylmer ("The Town"), Union Gas Limited ("Union"), Integrated Grain Processors Co-Operative Inc. ("IGPC") and Vulnerable Energy Consumers Coalition ("VECC") applied for and were granted intervenor status.

In Procedural Order No. 1 issued on April 1, 2010, the Board made provision for the initial steps in the proceeding including the filing of interrogatories and responses.

Pursuant to Procedural Order No. 3 issued on May 28, 2010, the Board convened a technical conference on June 14, 2010 to address further questions arising from the response to interrogatories and to seek clarification on the evidence filed by the Applicant. The technical conference was immediately followed by a settlement conference. At the end of the settlement conference, the parties agreed to continue discussions on June 28th with the objective of reaching a settlement among the parties. Union did not participate in the settlement conference.

The June 28th discussions led to a settlement on some of the issues. On August 3, 2010, IGPC filed a Notice of Motion in EB-2006-0243. That proceeding was a Leave to Construct application by NRG directed to the facilities required to supply IGPC with natural gas. The Board decided to hear that Motion contemporaneously, given its apparent relevance to the unresolved issues. In the Motion, IGPC indicated that although the facility is in service, IGPC and NRG have not been able to resolve differences over the costs of constructing the pipeline and IGPC requested that the Board resolve these matters.

The Board issued Procedural Order No. 5 on August 9, 2010 to deal with the Motion. The Board scheduled an oral hearing on September 7, 2010 to hear the Motion which was immediately followed by the rates case hearing.

At the commencement of the hearing of the Motion, the Board requested submissions from the parties on the most effective manner in which to proceed given the apparent overlap of issues raised in the Motion and the matters to be determined in the rate case application. The Board ultimately determined that it would hear the issues identified in the Motion that had potential rate impacts as part of the rates case proceeding.

The Board accepted the Settlement Agreement (Partial) that was filed by NRG on August 18, 2010 at the oral hearing.

At the conclusion of the oral hearing on the rates application the Board instructed the Parties to limit subsequent arguments to the rates matters. IGPC indicated it would comply with the Board's expectation that IGPC would recast its motion once informed by the Board's decision on the rates matters.

The pre-filed evidence of the Applicant included a proposal on an Incentive Regulation Mechanism ("IRM") and was identified in the Settlement Agreement as an unsettled issue. However, the Applicant decided at the oral hearing that it would prefer to file its IRM plan as a Phase 2 of the proceeding at a later date. The parties and the Board agreed to defer IRM to a later date and to establish 2011 base rates as part of the current phase of the proceeding.

THE ISSUES

The issues that remained unsettled were raised in the submissions filed by Board staff, IGPC, VECC and the Town of Aylmer. These have been addressed in the following sections of the Decision:

- Capital Cost of the IGPC Pipeline
- Removal of Ancillary Business from Rate Base
- IGPC Period Costs
- Amortization Period of Regulatory Costs
- NRG Gas Costs
- Deferral and Variance Accounts
- Cost of Capital and Capital Structure
- Cost Allocation

Two issues were not raised as concerns by Board staff or intervenors and were not addressed in the Settlement Agreement. However, NRG has sought approval on these two matters. This includes an approval of the revised rules and regulations and a new schedule for service charges. The Board approves NRG's revised rules and regulations and the schedule for service charges as filed.

RATE BASE

Capital Cost of the IGPC Pipeline

IGPC submitted that the pipeline should close to rate base no later than August 1, 2008 and not October 1, 2008 as proposed by the Applicant. IGPC noted that Union Gas began charging NRG for distribution services related to the ethanol facility on July 1, 2008. NRG commenced invoicing and IGPC commenced paying the full delivery charges as of July 15, 2008. IGPC indicated that from July 15th to September 30, 2008, IGPC paid $372,949.82 to NRG for distribution services.

IGPC argued that according to the OEB's Accounting Handbook, a utility is to cease charging interest and to commence charging depreciation when the pipeline is placed into service. IGPC submitted that the pipeline was placed into service on or before July 15, 2008. IGPC further argued that as of July 15, 2008, NRG was being fully compensated through rates paid by IGPC.

In the alternative, IGPC submitted that if October 1, 2008 was the appropriate date for closing to rate base, then it was inappropriate for NRG to charge full delivery rates for the period July 15, 2008 through September 30, 2008. Accordingly, IGPC submitted that NRG refund IGPC $372,949.82 less any amounts paid to Union and less any amounts payable pursuant to Rate 1.

NRG in its Reply submitted that the appropriate date for closing the IGPC pipeline should be October 1, 2008 as proposed in the Application. NRG argued that depreciation was supposed to reflect the deterioration of an asset and according to NRG the pipeline began to deteriorate and the asset value began to diminish with the first month of full gas flow, which was October 2008.

Board Findings

IGPC in its submission referenced a range of cost categories related to the IGPC pipeline. However, a number of the cost items in dispute do not impact the rate base or rates for 2011. The Board notes that the amount of the pipeline that is added to rate base is not a function of the cost of the pipeline but is derived from the calculation of the future revenue stream over a fixed number of years. The Board will therefore make a determination only on those matters that impact rates and not all costs that are in dispute.

The oral testimony indicates that the in-service date of the pipeline was just after July 1, 2008[1]. The commencement date under the gas delivery agreement was July 15, 2008 and IGPC commenced paying the full delivery charges as of July 15th. NRG has argued that very little gas flowed prior to October 2008. However, the pipeline was in-service after July 1, 2008. The definition of "In-Service" as noted in the Pipeline Cost Recovery Agreement[2] refers to the date on which the pipeline is able to deliver the full amount of gas contemplated by the Gas Delivery Contract. Based on this definition the Board has determined that the pipeline was used and useful as of the in-service date.

Accordingly, the Board agrees with IGPC that the pipeline should be closed to rate base on August 1, 2008 and NRG is ordered to make the appropriate changes in its Draft Rate Order to reflect this date.

Removal of Ancillary Business from Rate Base

Apart from the capital cost of the IGPC pipeline, all other capital expenditure items were largely settled. However, the Town has submitted that the Board should order NRG to remove any capital property associated with its ancillary businesses from rate base.

The Town submitted that NRG's rate base of $13.6 million for 2011 should be reduced by approximately $1.7 million in order to exclude assets which are related to ancillary businesses. The Town maintained that NRG's own evidence supports the concern that the ancillary businesses are not sufficiently profitable to justify ratepayers paying a regulated rate of return on these assets. The Town further noted that other regulated gas utilities have separated their ancillary services from their regulated business.

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[1] Oral Hearing Transcript, Volume 1, page 60

[2] IGPC Motion, August 3, 2010, Tab 3, Pipeline Cost Recovery Agreement, Article 1 – Attachments and Interpretations, Page 3

The Town submitted that the inclusion of the ancillary businesses obscures the financial situation of NRG's regulated business in an undesirable and inappropriate manner and there is no benefit to ratepayers to include them in NRG's rate base for ratemaking purposes.

In Reply, NRG refuted the Town's claim that the ancillary businesses are not sufficiently profitable. NRG submitted that its response to Undertaking J3.1 shows that the ancillary services income after tax since 2006 has been around $200,000, which is more profitable than NRG's utility business.

NRG further noted that the cost allocation methodology employed by NRG ensured that the rate base, operating, maintenance and administration ("OM&A"), depreciation and taxes were appropriately split between the regulated and ancillary businesses.

Board Findings

The Board has historically allowed NRG to keep its ancillary business within the regulated entity. The Board is satisfied that the current cost allocation methodology appropriately separates the costs and assets of the regulated and ancillary business.

The Board considers this longstanding situation to be somewhat unique, and generally inconsistent with good regulatory practice. However, given that this situation has prevailed for a considerable period, the Board does not consider the record in this case on this issue to be sufficiently focused to justify the unbundling sought by the Town. This decision ought not to be seen to have any particular precedential value, and the parties should feel uninhibited in bringing the matter forward in future proceedings.

COST OF SERVICE

IGPC Period Costs

IGPC in its submission disputed the levels of certain OM&A costs. One such issue concerns depreciation. As noted above, IGPC argues that a lower total amount be closed to rate base. It argues that consequentially, a lower depreciation amount should be provided for. The other contested costs items include insurance costs and maintenance costs. The Board will address insurance and maintenance costs below.

Insurance

NRG has added the IGPC pipeline to its overall insurance coverage and has opted for additional coverage in certain areas. Consequently, NRG is seeking to recover total insurance costs of $284,925 for the 2011 Test Year. A majority of the premium is sought to be recovered from IGPC.

Pursuant to Undertaking J2.6, NRG reduced the amount to be recovered from IGPC through rates from $221,330 to $173,067. IGPC in its arguments submitted that NRG's revision still overstates the appropriate cost of insurance. IGPC noted that NRG had not obtained multiple quotes but relied on its current insurance provider for the additional coverage.

<u>Business Interruption Insurance</u>

This is a new insurance policy that NRG is proposing to recover through rates and allocate 100% of the cost to IGPC. IGPC argued that the Board did not have sufficient information to ascertain whether this cost has been prudently incurred, is an appropriate expense to recover from ratepayers, and whether the insurance policy addresses a risk specific to IGPC. IGPC claimed that there was no evidence that the business interruption insurance was a typical expense incurred by other regulated gas utilities.

IGPC further argued that the business interruption insurance which is triggered when service to a customer is interrupted and where the customer has no obligation to pay is a typical business risk and shareholders are compensated for these risks through the return on equity. Furthermore, IGPC argued that there was no evidence that coverage is restricted to interruption of service to just IGPC. Consequently, IGPC submitted that NRG had not substantiated that the cost of the business interruption insurance was prudently incurred, and irrespective of whether it was prudently incurred, IGPC was of the view that the nature of the coverage is such that the costs should be borne by the shareholder and not the ratepayers. On that basis, IGPC submitted that the Board should disallow the recovery of the cost of the business interruption insurance through rates.

<u>General Liability, Umbrella and "Additional Insurance"</u>

IGPC in its submission claimed that there was not enough evidence to support the proposition that IGPC was the causal factor in the incurrence of the premium costs. IGPC further added that there was no evidence that the umbrella and additional umbrella policies insured against risks that were different from those insured under the general liability policy or that the umbrella policy specifically addressed risks imposed on NRG by IGPC.

Transfer Station Insurance

NRG has allocated 100% of the transfer station insurance costs to IGPC. IGPC submitted that it questioned the logic of incurring an expenditure of $35,387 to insure a station that costs $884,003 for an amount of $1,785,000.

NRG in its Reply noted that on examining its existing liability coverage and after discussions with its insurers, it was determined that it needed additional coverage. Consequently, NRG increased its umbrella liability coverage and it found it far more cost effective to expand coverage under its existing policy rather than set up a new policy for the additional coverage. NRG submitted that since this coverage was added as a result of the IGPC pipeline, IGPC should be allocated 100% of the costs.

With respect to the business interruption insurance, NRG confirmed that it exclusively covers the risks associated with interruption of supply to IGPC and does not cover business interruptions on the other portions of the NRG distribution system. Specifically, this insurance allows NRG to recover its fixed costs associated with the IGPC pipeline. In Reply, NRG maintained that with the addition of IGPC, its revenue structure had been altered significantly considering that one customer was responsible for 29% of the revenue. As a result, NRG considered it prudent to insure against the possibility of an incident wiping out approximately 30% of its revenues for an extended period. Given the size and importance of IGPC to NRG's business, NRG submitted that contrary to IGPC's suggestion, the business interruption insurance was not for the benefit of NRG's shareholder but for all of NRG's ratepayers. NRG submitted that it was appropriate to allocate the cost of the insurance to the entity that caused the cost to be incurred as this was consistent with ratemaking principles.

With respect to the transfer station insurance, NRG clarified that the cost included stations at either end of the IGPC pipeline as well as a station in the middle of the IGPC pipeline which houses the shut-off valve. According to its evidence transfer stations are not typically covered by property and building insurance and the premium was higher than that associated with office buildings due to the fact that the pipe went directly through the station.

Pipeline Maintenance Costs

NRG has a maintenance contract with MIG engineering for providing ongoing maintenance of the IGPC pipeline. NRG is seeking to recover $112,109 for maintenance of the pipeline and $43,050 for maintenance of the customer station. IGPC in its argument referred to the Leave to Construct Application that included $38,000 for maintenance of the pipeline and customer station. IGPC noted that the actual contract value far exceeds the amount estimated in the Leave to Construct Application. IGPC further noted that the contract was sole sourced to a company with no pipeline maintenance experience. IGPC submitted that if the maintenance work was to be carried out on an annual basis to comply with regulatory requirements, the task should have been already performed twice and underlying historical costs would have existed. IGPC further maintained that NRG had made no attempts to ensure that the practice was consistent with other gas utilities in the province.

NRG in its Reply noted that the costs were third party costs pursuant to a maintenance contract and NRG made no profit from this arrangement. NRG further noted that the while IGPC relied on the $38,000 estimate provided in the Leave to Construct Application it had disregarded other estimates appearing in the same application.

NRG noted that it had no experience in maintaining high pressure steel pipelines. NRG therefore considered it prudent to outsource the maintenance to a qualified third party and was of the opinion that the services outlined in the MIG proposal were commensurate with good utility practice. The reason NRG sole sourced the contract to MIG was because MIG had constructed the IGPC pipeline on time and within budget. Furthermore, MIG is located close to NRG’s service area.

NRG noted that the maintenance contract of $112,109 represented 1.3% of the capital cost of the facility and was considered reasonable in relation to the capital cost of the pipeline.

Referring to specific elements of the MIG contract, IGPC in its arguments disputed the following items:

Pipeline Markers – IGPC claimed the NRG employees were capable of carrying out this work. NRG in its Reply argued that it had approached the maintenance of the pipeline as a comprehensive program and did not consider it appropriate to split it into bits and pieces.

Weekly Observations – IGPC submitted that weekly inspection of the pipeline costing $12,350 was overkill and bi-weekly inspections were more appropriate considering the limited amount of development in the Aylmer area. NRG responded by asserting that weekly inspections were appropriate and there was no basis for suggesting a different cycle.

Community Awareness ($8,000) – IGPC claimed that meetings with fire departments and other groups should deal with all natural gas fires and there was no indication that the program was solely as a result of having a steel pipeline. In Reply, NRG reiterated that the entire maintenance contract was to serve the IGPC pipeline.

Emergency Response (Mock Emergency Training, $18,000) – IGPC maintained that in case of third party damage to the pipeline, the third party would be responsible for such costs and these costs should not be passed along to IGPC. NRG in response rejected the views of IGPC and maintained that an incident on the pipeline could cause catastrophic damage. Mock emergency training was therefore a prudent cost.

Technician Training – IGPC submitted that it was inappropriate for it to pay for training employees of a subcontractor considering that they would need to be trained and competent in the first place to perform the task. NRG in Reply stressed that training NRG staff on safety manuals related to the IGPC pipeline was appropriate and the information was not generic but rather specific to the IGPC pipeline.

Third Party Observations ($4,680) – IGPC submitted that costs for third party observations should be recovered from third parties such as municipalities or developers requiring such services in line with the remainder of the distribution system. In Reply, NRG confirmed that it provides line locates and third party observations free of charge on its main system.

MIG Costs – In its argument IGPC suggested that $19,500 was related to making the pipeline piggable which was a capital expenditure item and should therefore be capitalized. NRG in response clarified that a one-time cost of $102,000 to make the pipeline piggable was included as a capital expenditure and not included in maintenance costs. NRG noted that IGPC had referred to the cost of the in-line inspection which is an OM&A item.

In its final remarks IGPC submitted that the Board should approve a direct allocation of $35,000 for maintenance to IGPC. In addition, IGPC maintained that the Board allocate the cost of Community Awareness and Emergency Response across all rate classes using rate base as the allocator. IGPC would then be allocated $4,500 for the two items noted above and a $35,000 direct allocation.

In Reply, NRG noted that the $35,000 referred to the initial estimate provided in the Leave-to-Construct Application and did not reflect the amount of the MIG contract.

Station Maintenance Costs

IGPC disputed the inclusion of Provincial Sales Tax ("PST") for expenditures related to the maintenance of stations. In Reply, NRG agreed with IGPC and noted that the Settlement Agreement included a PST reduction of $3,189 related to station maintenance. NRG agreed to revise the cost allocation model to reflect this change.

Board Findings

Insurance Costs

One of the major items under dispute is business interruption insurance. Although the evidence is not clear on the coverage provided, it seems that the insurance would cover fixed costs and expenses[3] in the event of a *force majeure*. However, there is no information on record with respect to the payment under the coverage, whether there is a deductible in place, the maximum days that the coverage is provided for in case of an event and how the coverage ties in with the contracts in place between NRG and IGPC.

The Board is also aware of a letter of credit that has been provided by IGPC to NRG in the event that IGPC were to become insolvent or shut operations. The letter of credit adjusts for the undepreciated value of the pipeline and essentially protects the other rate classes and the shareholder. In other words, the letter of credit allows for recovery of depreciation. In case of a *force majeure* event, the letter of credit would be extended for an additional period to reflect the duration of the specific event. In other words, NRG would be guaranteed recovery of depreciation despite the declaration of *force majeure*. However, it seems that the coverage through the business interruption insurance would recover fixed costs and expenses during a *force majeure* event. This would imply that a portion of the insurance coverage would recover depreciation expenses of the pipeline during a *force majeure* event. The recovery of depreciation through the business

[3] Oral Hearing Transcript, Volume 2, page 61, line 16

interruption insurance will not adjust the amount of the letter of credit during the *force majeure* period. This would lead to NRG recovering the same depreciation expense twice, once during the *force majeure* period and later due to the extension of the duration of the letter of credit.

The Board has determined that with the exception of business interruption insurance, NRG is allowed to recover its total insurance cost of $259,345 ($284,925 less $25,580 representing business interruption insurance premium).

Maintenance Costs

The evidence indicates the existence of two contracts to maintain the IGPC pipeline. One is the contract with MIG Engineering Ltd. to provide administration and engineering services for the IGPC pipeline and the other contract is with Lakeside Process Controls Ltd. to maintain the transfer stations associated with the IGPC pipeline.

IGPC in its submission had expressed concerns about the MIG contract. In case of the contract for the maintenance of transfer stations, NRG agreed to resolve the only issue, that is, the reduction of PST. The Board is satisfied with the contract to maintain the transfer stations and the adjustment agreed to by NRG. The Board will therefore make a determination only on the MIG contract.

The Board is concerned that the contract was sole sourced and there is not enough evidence that all the elements of the contract are required to fulfill the safe administration and maintenance of the pipeline. The Board therefore orders NRG to tender the maintenance of the pipeline and provide written bids to the Board. Specifically, the Board directs NRG to first retain the services of an independent expert in the development of maintenance programs for pipelines similar to that employed in the supply of gas to IGPC. That expert will be retained by way of tender, and all of the documentation associated with that tender will be filed with the Board and the intervenors of record. Following the development of a maintenance protocol NRG shall retain the services of an enterprise experienced in the provision of such services by way of tender predicated on the maintenance protocol. All of the documentation associated with the retention of the maintenance firm will be filed with the Board and the intervenors of record. In the meantime the Board will allow NRG to recover in 2011 rates, 50% of the amount of the contract, which translates to $56,055. The balance will be moved to a pipeline maintenance deferral account to be adjusted once the Board determines the appropriate maintenance amount. NRG is ordered to provide the written bids associated with the development of the maintenance protocol to the Board within one month of the date of the Decision. The Board will review proposed pipeline maintenance costs in Phase 2 of the proceeding.

Deferral and Variance Accounts

NRG has requested the following approvals from the Board with respect to its deferral and variance accounts:

1. A request to establish the International Financial Reporting Standard ("IFRS") deferral account.
2. A request to reset the Purchased Gas Transportation Variance Account ("PGTVA"), and replace the single reference price with two different prices, one for Rates 1 to 5 and one for Rate 6.
3. A proposal to dispose of the net balances in the Regulatory Expenses Deferral Account ("REDA") and in the PGTVA as of September 30, 2009 through a rate rider.
4. A proposal to assign IGPC with its appropriate share of the balance in the PGTVA by developing a fixed charge rate rider and assigning the appropriate balances to other rate classes based on volumetric deliveries in the 2010 Bridge Year. The net amount is proposed to be recovered from customers over the 12 months of the 2011 Test Year through a fixed charge rate rider.

The only issue raised by intervenors and staff related to the balances in the REDA and NRG's proposal to recover $111,123 for legal expenses incurred in the Union Cessation of Service proceeding (EB-2008-0273).

NRG's position was that the Board order that NRG's shareholders should bear the costs of that proceeding, extended only to the intervenor costs. In its view, its costs for the proceeding could be recovered from ratepayers[4]. Board staff and VECC did not agree with this view and submitted that the Board clearly indicated that NRG could not recover any costs from ratepayers.

The EB-2008-0273 Decision states on page 7 –

> "In the case of Union's request for security, NRG did not act in a timely manner. The record suggests that NRG essentially stone-walled Union. This resulted in significant costs for Union, the Board, the Town of Aylmer and the Integrated

[4] Oral Hearing Transcript Volume 1, Page 112

> Grain Processors Co-Operative. This type of brinkmanship is not helpful where 6,500 customers and a recently activated ethanol plant supported by substantial Federal and Provincial funding are involved. **The Board also directs that costs being paid by NRG shall be paid by NRG's shareholder and not passed on to the NRG rate payers.**" (emphasis added)

Board staff and VECC in their final arguments submitted that the Board was clear in the EB-2008-0273 Decision that all costs being paid by NRG were to be borne by the shareholder and not by NRG ratepayers. VECC further added that the concerns raised by Union with respect to the financial viability of NRG related to the issuance of retractable shares by NRG in favour of its shareholder. VECC submitted that the application essentially resulted from NRG's actions in relation to its shareholder's interest and not to the interest of its ratepayers.

Accordingly, Board staff and VECC submitted that NRG should not be able to recover the amount of $111,123 that it had requested for disposition in the REDA.

In its Argument-in-Chief, NRG indicated that the retractable feature of NRG's common shares had been in existence before 2006 and there was no change in NRG's financial condition, rather there was a change in the accounting rule. NRG further clarified that it had never missed a payment and the Board's assessment that NRG had "stone-walled" Union was incorrect. NRG argued that it was merely protecting its shareholder and ratepayers from an unreasonable request.

NRG further added that Union did not gain anything from the proceeding since the Board merely ordered NRG to postpone the retraction of shares in favour of Union.

In Reply, NRG submitted that the Board's wording in the Decision around costs had to be understood in the specific context. NRG argued that the costs incurred by a utility in a proceeding are never the subject of consideration in a cost awards section of the Board. When the Board adjudicates for cost awards, it typically refers to costs awarded to intervenors. NRG submitted that the EB-2008-0273 Decision does not suggest that the Board referred to all costs.

NRG also refuted VECC's assertion that the proceeding related to NRG's shareholder. NRG noted that since the Board did not order NRG to post financial assurance or change its contract date with Union, it did benefit NRG ratepayers.

NRG further noted that the Board did not have the specialized expertise in the field of cost awards and essentially departed from the general rule applicable to costs by ordering NRG's shareholder to pay intervenor costs. As ordered, NRG's shareholder paid these costs.

NRG submitted that if the shareholder is now asked to pay for NRG's legal expenses, it would be an incorrect and unsupportable decision.

Board Findings

The Board approves NRG's proposal for the creation of the IFRS deferral account in accordance with Board guidelines in the Report of the Board titled *Transition to International Financial Reporting Standards* (EB-2008-0408).

The Board also approves NRG's proposal for the PGTVA and the clearance of the account as of September 30, 2009.

With respect to whether NRG should be able to recover the legal costs associated with the Union Cessation of Service proceeding, the Board has determined that it will allow NRG to recover the costs amounting to $111,123. In the Board's EB-2008-0273 Decision, the Board ordered NRG to pay the costs and denied recovery from ratepayers. However, the decision does not explicitly state that NRG cannot claim its own costs. The Board agrees with NRG that Board decisions typically refer to costs in the context of intervenor or third party costs as opposed to legal costs of the utility.

Amortization Period of Regulatory Costs

Parties agreed to the quantum of regulatory costs in the Settlement Agreement. However, since the parties did not reach an agreement on the IRM plan and the parties and the Board agreed to move IRM to Phase 2 of the proceeding, the appropriate amortization period of regulatory costs in the absence of an IRM framework remained an outstanding issue.

The Settlement Agreement was premised on regulatory costs of $450,000 being amortized over 5 years matching the term of the IRM plan. A component of this cost includes $54,000 related to future administration of the IRM plan.

VECC was the only party to raise this issue in submission. VECC submitted that the total amount of regulatory costs should be reduced by $54,000 and the remaining

$396,000 should be amortized over a four year period rather than a 3 years time horizon as suggested by NRG.

VECC also submitted that the recovery of the $396,000 should be recovered through a rate rider as opposed to be included in base rates. This is in the event that NRG does not get approval for an IRM and does not return for rebasing within the four year period. In case an IRM is approved, the remaining $54,000 related to IRM administration costs can be embedded in rates for the IRM period.

In Reply, NRG indicated that its views were not very different from VECC's but rather followed a different approach. NRG clarified that it has not withdrawn its request for an IRM plan rather it has moved it to Phase 2 under the same proceeding. NRG proposed that under a five year IRM plan $90,000 of regulatory costs should be included in rates and under a four year IRM $116,400 should be recovered in years 2 to 4. In case a three year IRM plan is approved, then $169,300 should be recovered in years 2 and 3. If no IRM plan is approved, then NRG's position was that $153,000 should be recovered in each of the two years following the 2011 Test Year.

The position of VECC and NRG differ significantly in their outcomes if the Board approves an IRM plan that is of three years duration or less. NRG's position was that being a small utility, a delay in recovering amounts related to regulatory costs had a considerable impact on the utility's cash flow. NRG further submitted that matching costs to the period that forms the basis for those costs was in line with regulatory rate making principles.

Board Findings

The quantum of regulatory costs has already been settled. The issue before the Board is the amount that is to be included in base rates for 2011. The IRM proposal is still before the Board and it is the Board's expectation that there will be some form of an IRM regime arrived at in Phase 2 of the proceeding.

The Board agrees with NRG's proposal that $90,000 should be included in 2011 rates and the remaining costs will be dealt with in Phase 2 of the proceeding.

NRG Gas Costs

In the 2006 rates Decision (EB-2005-0544), the Board approved a specific methodology for NRG to calculate the contract price for gas purchased from the related company, NRG Corp. The contract price was to be recalculated on an annual basis and, in the event that the source from which prices are calculated or the methodology used to determine the price changed, NRG had to seek prior permission from the Board.

In response to Board staff IR #23, the Applicant indicated that the previous management of NRG neglected to follow the Board directive and did not recalculate the purchase price. In other words, the price remained unchanged from 2007 onwards. Board staff in their submission identified several issues associated with gas purchased from NRG Corp.

Overpayment by NRG Ratepayers and Determining Purchase Price in Future

At the oral hearing, NRG confirmed that as of September 30, 2010, the failure to follow the Board-prescribed methodology will result in an overpayment of approximately $97,000 to NRG Corp[5]. Board staff suggested that the amount of $97,000 should be refunded to ratepayers and, unless and until the Board recommends an alternative framework for pricing gas, NRG should record the credit/debit balances to the Purchased Gas Commodity Variance Account ("PGCVA") as of October 1, 2010 until the purchase price is reset on the basis of the Board's original direction.

At the oral hearing, NRG indicated that the distribution system in the southern district requires dual supply from NRG Corp. gas wells to provide adequate supply and maintain system pressure. NRG estimated that 2.4 million cubic meters was required from NRG Corp. in order to maintain system pressure[6].

In its Argument-in-Chief NRG suggested a dual approach to pricing gas purchased from the related entity. The proposal was to:

- pay NRG Corp. $8.486 per mcf whenever the market price for natural gas is $9.999 per mcf or less; and,
- pay "market price" for natural gas when gas is $10.00 per mcf or higher.

In submission, Board staff dismissed NRG's approach and recommended a market price for all gas purchased from NRG Corp. In case NRG wanted to purchase gas from NRG Corp. at a price above market, Board staff submitted that NRG be allowed to recover only the market price from ratepayers.

[5] Oral Hearing Transcript Volume 1, Page 114
[6] Oral Hearing Transcript Volume 1, Pages 118-119

In Reply, NRG submitted that a single market for all gas fails to recognize the benefit that has accrued to ratepayers over the years as a result of NRG Corp. wells producing and supplying gas in the southern service area. The pricing mechanism proposed by staff did not recognize that NRG Corp. could simply refuse to sell in times of low natural gas prices and shut down its wells. If NRG customers were unable to get the minimum required quantities from NRG Corp. required to maintain system pressure, then they would be faced with an alternative of a pipeline costing approximately $1.9 million outlined in the Argument-in-Chief. NRG submitted that its pricing methodology was sound, workable and transparent.

With respect to ratepayers overpaying for the price of gas to the extent of $97,000, NRG submitted that if the Board were to adopt NRG's proposed pricing methodology then no refund would be required since the Board's approval would implicitly provide that the current price being paid to NRG of $8.486 for system integrity gas was appropriate. However, Board staff dismissed this suggestion indicating that any proposal approved by the Board would be effective at a future date and would not be applied retroactively.

In its Reply NRG proposed a revision to the EB-2005-0544 pricing methodology and suggested adjusting the price on a quarterly basis. Board staff supported this proposal and also supported NRG's suggestion of using the Shell Trading Report as the source to calculate the purchase price. Alternatively, Board staff submitted that NRG could also use Union's Quarterly Rate Adjustment Mechanism ("QRAM") and use Union's *Ontario Landed Reference Price* to fix the purchase price of gas.

Transportation Charge

NRG confirmed at the oral hearing that NRG Corp. sells gas to Union and the gas flows through NRG's distribution system. However, NRG Corp. does not pay NRG a transportation charge for using the NRG system to transport gas to Union.

In response to Undertaking J2.8, NRG provided total volumes that were routed through NRG's distribution system by NRG Corp. Using the rate that NRG Corp. pays to Greentree Gas & Oil Ltd. for transporting gas to Union, Board staff estimated that ratepayers were deprived of $31,297 in revenues since 2006.

Board staff submitted that NRG should be directed to charge NRG Corp. a transportation rate of $0.95 per mcf and an administrative charge of $250 per month for every month the NRG distribution system is used by NRG Corp. to transport gas (based on the charges of Greentree Gas & Oil Ltd.). In addition, since NRG had not forecasted revenues for transportation in the current proceeding, Board staff submitted that the Board should establish a deferral account to track revenues from transportation which can be cleared through the annual deferral account disposition mechanism.

NRG agreed to this proposal in Reply.

Engineering Study to Explore Alternatives

At the oral hearing, Board staff sought alternatives from NRG in case all natural gas wells of NRG Corp. were to run dry and NRG was no longer able to obtain the required quantities to maintain system pressure. In the undertaking response NRG indicated that based on informal discussions with engineering firms, NRG would have to build a new pipeline to source additional gas and maintain system pressure at an estimated cost of $1.89 million excluding regulatory, financing and land acquisition costs.

In its submission Board staff advocated an independent third party engineering study which would identify options (including high level cost estimates) to maintain system pressure in the absence of supply from NRG Corp.

Furthermore, in recognition of the fact that NRG ratepayers had been subsidizing the shareholder for the past number of years by way of transporting NRG Corp. gas for free, Board staff submitted that the cost of the independent engineering study to explore alternatives to buying Integrity Gas be borne by the shareholder and not the ratepayers.

In Reply, NRG dismissed the suggestion of the shareholder paying for the study and noted that Board staff's approach was not even-handed and the focus seemed to be to find a benefit to NRG's related company to justify imposing the cost of the study on NRG. NRG further submitted that Board staff had ignored the fact that the real beneficiaries of the system integrity issue were ratepayers who had benefitted from this arrangement for years. NRG ratepayers have benefitted from having a materially smaller asset base for years as a result of NRG Corp.'s gas exploration, development and production activities. Assuming the cost of a new pipeline at $1.89 million to resolve the issue of integrity gas, ratepayers would pay an additional $80,000[7] in the first year for this alternative. This amount was far greater than the $31,927 that was not paid by

[7] The $80,000 estimate refers to the return on equity on an additional $1.89 million to rate base.

NRG Corp. to NRG for gas transportation over a five year period. NRG submitted that if a study was required, the costs should be borne by ratepayers.

NRG further requested the Board to consider the cost benefit of such a study and determine whether NRG should first submit quotes on the cost of conducting a study. The cost could then be considered in Phase 2 of the proceeding.

Deemed Application of the Affiliate Relationship Code

Although NRG Corp. is not an affiliate of NRG as defined in the Affiliate Relationships Code (which adopts the definition from the *Ontario Business Corporations Act)*, Board staff expressed concern that the nature of the relationship presents the possibility that NRG Corp. is benefitting at the expense of ratepayers. Board staff submitted that although NRG Corp. is not technically an affiliate, the provisions of the Board's Affiliate Relationship Code ("ARC") should be made to apply to the relationship between NRG and NRG Corp. Board staff cited the Dawn-Gateway Decision (EB-2009-0422) as an example where the Board determined that the provisions of ARC should apply to the relationship between Union and Dawn Gateway even though Dawn Gateway was not technically an affiliate of Union.

In Reply, NRG submitted that the application of ARC was unnecessary and Board staff had not demonstrated a specific issue that would be resolved as a result of the application of ARC. Moreover, NRG argued that ARC would impose additional regulatory burden on a small utility like NRG with no real benefit to ratepayers.

NRG maintained that the Board has the ability to examine the relationship and dealings between NRG and NRG Corp. in rate proceedings. NRG further noted that if its proposal of adjusting the gas price purchased from NRG Corp. on a quarterly basis as part of NRG's QRAM was accepted then there would be sufficient disclosure of the arrangement in QRAM proceedings.

Board Findings

Board staff identified several issues respecting the cost of gas procured by NRG for distribution to its customers. The Board will deal with each of them in the following section.

Transportation Charge

NRG has agreed to incorporate a transportation rate and administrative charge for providing transportation services. The Board orders NRG to include a transportation charge in the rate schedule accompanying the draft rate order. NRG will also record transportation revenues in a deferral account which will be reviewed in future proceedings.

Refund of Overpayment of $97,000

NRG's evidence indicates that the overpayment by NRG to NRG Corp. for gas purchases as of September 30, 2010 is $97,000. This has occurred as a result of the failure of NRG to follow a Board order in EB-2005-0544. The Board is concerned that the management of NRG failed to follow a previous Board order. NRG is now arguing that it would not have to refund the amount if the Board accepts its gas pricing proposal. The Board notes that the amount of the refund is as a result of non-compliance and has no bearing on the price mechanism that the Board puts in place for the Test Year and beyond.

The Board orders NRG to refund the $97,000 to ratepayers in the form of a rate rider for the 2011 Test Year. The Board also orders NRG to track amounts as of October 1, 2010 in the PGCVA until the implementation of a new price mechanism outlined in this Decision.

Gas Contract Price Determination

NRG requires 2.4 million cubic meters of gas annually from NRG Corp. in order to maintain system integrity in the southern part of the distribution system. NRG has proposed to price this gas differently as compared to other gas that it requires. Essentially, NRG has proposed to purchase the integrity gas at a minimum price $8.486 per mcf. Board staff objected to this suggestion and argued for applying market prices to all gas.

The Board considers this to be a unique situation and it is difficult to determine at this point in time whether a cost effective alternative exists. The Board also notes that NRG's proposal of $8.486 per mcf is fairly high considering that current gas prices are under $5.00 per mcf and not expected to fluctuate significantly in the short term. However, considering the unique circumstances of this issue the Board will allow NRG on a temporary basis to pay NRG Corp. a price of $6.80 per mcf or market price, whichever is higher, for gas required to maintain system integrity.

For all other gas, the Board has determined that NRG will use Union's *Ontario Landed Reference Price* every quarter to adjust the contract price with NRG Corp. This will allow NRG to align the price adjustment with its own Quarterly Rate Adjustment Mechanism since Union files its application in the first week of the month prior to the rate change. In addition, this approach will reduce the administrative and regulatory burden of NRG.

Study to Explore Alternatives to Maintaining System Integrity

Board staff proposed an independent engineering study to identify options and obtain cost estimates for a solution to maintaining system pressure in the southern service area. The Board has already determined a short-term solution to pricing of integrity gas. However, a long term solution is required and an independent engineering study would assist the Board in determining whether there is a cost effective permanent solution.

The Board fails to understand why NRG does not have sufficient information about its distribution system to indentify the precise alternatives available. The Board also believes that NRG should have been proactive in finding a solution to this problem.

The Board orders NRG to submit the terms of reference for an engineering study within two weeks from the date of this Decision. Once the Board approves the terms of reference, NRG is ordered to provide a report within three months. The cost of this study will be borne equally by the shareholder and ratepayers.

Application of ARC

The Board is concerned about the relationship between NRG and NRG Corp. and its impact on ratepayers. However, the Board has addressed ratepayer issues through the establishment of a transportation rate and an independent pricing mechanism for the purchase of gas from NRG Corp. In addition, the Board will review the dealings between NRG and NRG Corp. in rate proceedings and during the review of NRG's quarterly rate adjustment process (QRAM). The Board is satisfied that it has addressed the major concerns and does not see any benefit in imposing the regulations of ARC on the relationship between NRG and NRG Corp at this point in time.

COST OF CAPITAL

Capital Structure and Return on Equity

NRG requested a deemed capital structure of 58% debt and 42% equity with a return on equity ("ROE") of 50 basis points over the Board determined ROE as per the Board's Cost of Capital Parameter Updates issued on February 24, 2010. In requesting a 42% equity ratio NRG relied on the opinion of its expert Ms. Kathleen McShane who indicated that the 42% ratio adopted by the Board in 2006 and a premium of 50 basis points over the Board determined ROE remains appropriate for NRG.

All intervenors including Board staff made submissions on the proposed capital structure and ROE. Board staff, VECC and IGPC submitted that the actual capital structure of NRG was essentially unstable and there were several methods of calculating the capital structure if factors such as gross (excluding the impact of compensating balance) versus net (including the impact of compensating balance) and the retraction provision of shares was considered.

Board staff submitted that the main reason that NRG received 42% equity ratio in the 2006 Decision (EB-2005-0544) was because that was the actual ratio and Ms. McShane's evidence was that the actual was the most appropriate value to use. The current actual capital ratio of NRG was 37% as indicated in the technical conference[8]. Board staff further referred to a table[9] in Ms. McShane's report that showed a majority of the utilities operated pursuant to a 40% deemed equity ratio.

IGPC submitted that since 2006 NRG had made no equity contribution and had added over $4.5 million to the rate base related to the IGPC pipeline. Notwithstanding this, NRG persisted in its claim for a 42% equity component, as in 2006.

VECC submitted that in fact NRG had very little or no equity considering that retractable shares were included as equity. The same view was echoed by the Town in its submission.

The Town in its submission proposed a different calculation to estimate the equity. It used the $3.4 million equity attributable to utility operations in 2006 as the starting point

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[8] Technical Conference Transcript, Page 54 (Lines 19-20)

[9] Table 4 in Exhibit E2/Tab 1/Schedule 1, "Opinion on Capital Structure and Equity Risk Premium for Natural Resource Gas"

and used the Board approved ROE of 9.2% for the years 2006 through to 2010 and came up with a 2011 number of $4.65 million. The Town submitted that the $4.65 million number should be used as NRG's actual equity underpinning its utility operations for the 2011 Test Year.

With respect to the Return on Equity, NRG's position was that NRG's risk profile remained unchanged from 2006 and it should therefore receive the same 50 basis points premium.

Board staff in its submission noted that the Board's *Report on Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 was released after the Board's Decision on NRG's 2006 Cost of Service Application. Board staff submitted that the equity risk premium of 550 basis points referred to in the report represents a risk premium that accounts for and considers all utilities across Ontario. In other words, the Board report recognized that the 550 basis points premium did not represent a specific utility but was generally applicable across all utilities. The Town made a similar argument noting that the 550 basis points premium was not based on the individual risk profile of Enbridge Gas and was therefore not appropriate as a base to which a risk premium should apply.

Board staff further noted that in some 2010 cost of service applications intervenors argued that the 550 basis points premium included 50 basis points for floatation and transaction costs. The intervenors submitted that utilities such as Haldimand County Hydro Inc. (EB-2009-0265) and Burlington Hydro Inc. (EB-2009-0259) do not incur any floatation or transaction costs and should therefore not receive the 50 basis points premium. The Board in its Decision agreed with the intervenors but determined that the policy should be applied unadjusted. The reason was that the Board already knew that a number of utilities in Ontario did not issue equity or debt to the public and this was understood throughout the evolution of the Board's approach to setting the ROE.

Board staff used a similar rationale to argue that during the evolution of the report the Board also knew that the utilities shared different risk profiles and were of different sizes but it did not make any distinction on this basis neither made an exception for any of the utilities.

Board staff submitted that there was no compelling evidence to indicate that NRG's risk profile was considerably different from most utilities in Ontario; the Board should therefore award NRG the Board determined ROE of 9.85%.

VECC supported Board staff's argument and noted that in the event the Board decided to depart from policy and award a 50 basis points premium, it would be completely offset by the inclusion of 50 basis points for transactional costs that NRG does not incur.

IGPC in its submission noted that NRG had presented no evidence of the specific risks that distinguish NRG's business from that of other Ontario electricity or gas distributors. With respect to adding the new pipeline, IGPC indicated that NRG was protected by contract terms that obligate contractual payments irrespective of delivery and a letter of credit for the value of the pipeline.

The Town in its submission maintained that the retractable shares that are considered as equity in the Application should in fact be treated as debt until the retraction feature is removed. Accordingly, the Town submitted that the Board should allow a 6.36% return on the value of retractable shares as opposed to 9.85%.

In Reply, NRG stressed that equity injections are atypical to the operation of small private utilities. In 2006, despite the shareholder taking a significant dividend, NRG's actual equity remained at 41.5%. However, with the addition of the IGPC pipeline it had understandably dropped but expected to recover with the retention of earnings. Although NRG's currently actual equity is 37%, NRG argued that over the term of the IR plan NRG's actual capital structure would be 43% equity and 57% debt on a net debt basis. NRG further reminded the Board that the IR plan had not been withdrawn but just moved to Phase 2 and the evidence was still live before the Board.

Addressing the issue of the retractable shares, NRG noted that they have been postponed in favour of the Bank and Union and as long as NRG has some debt, the shares will be postponed in favour of the Bank.

NRG also rejected the Town's method of calculating equity using 2006 utility attributable equity as the starting point and adding a rate of return from 2006 to 2010. NRG argued that the Town had confused retained earnings with over-earning and failed to recognize the concept of just and reasonable rates.

NRG referred to the table[10] in Ms McShane's report and noted that if data for the Ontario electric distribution utilities was omitted, the average equity ratio for the rest of the individual companies was 41.6%.

NRG also referred to the "fair return standard" in the Cost of Capital Report and noted that ultimately the Board determined capital structure and ROE should provide the utility with a fair return. NRG submitted that in an attempt to move to a standardized approach for establishing capital structure and ROE, the Board needed to consider whether the standards provided the utility with a fair return. NRG further argued that mechanically applying the standards would amount to a fettering of the Board's legal discretion.

NRG submitted that the capital structure and ROE established by the Board do not provide a fair return and there was no evidence in the proceeding that supported a different finding from the Board's determination in NRG's previous rates case (EB-2005-0544)

Board Findings

There is no consensus on how to determine NRG's capital structure. NRG has itself provided the capital structure on a gross versus net basis. The issue is further complicated by the nature of its shares, which are retractable in nature and classified as a liability according to Canadian Generally Accepted Accounting Principles. The Board is not confident that a definitive number can be established from the Applicant's evidence and record in this proceeding.

The Board has a Cost of Capital policy in place that is applicable to all electric utilities and NRG's size and profile is similar to a number of electric utilities as opposed to the other two large gas utilities (Enbridge and Union). The Board policy on the appropriate equity ratio is 40% and is not considerably different from the ratio sought by NRG.

NRG has submitted that due consideration should be given to the fact that over the term of the five-year IR plan, the actual debt-equity structure would average 53:47 on a gross debt basis. However, the Board in this proceeding is making a determination on 2011 rates. The Board duly notes that an IR plan remains an issue before the Board but the base year rate determination process does not take into account average forecasts for

[10] McShane's Opinion on Capital Structure and Equity Risk Premium for NRG Exh. 2/Tab1/Sch.1, Table 4, page 21

the entire IR period. This is not done for other areas such as capital expenditures or OM&A. The argument that capital structure should, alone among all other elements, be an area where a five year forecast should be considered in determining an appropriate ratio for the Test Year seems inappropriate.

The Board has determined that the appropriate capital structure for NRG is 40% equity, 56% long-term debt and 4% short term debt in accordance with the Board's 2006 Cost of Capital Report[11].

NRG has requested a risk premium of 50 basis points over the Board determined ROE. The Board's current ROE applies to all regulated utilities in Ontario and the Board's 2009 Cost of Capital Report does not make any distinction on the basis of size or risk. The Board during the evolution of setting the ROE already knew that the utilities that it regulates were of different size and risk profiles. This distinction was considered when the 550 basis points premium was determined. NRG has presented no evidence that its risk profile was significantly different from other utilities in Ontario. The Board believes that 9.85% is appropriate and orders NRG to incorporate this ROE in the Draft Rate Order.

NRG alludes to the fair return standard as a legal obligation on the Board. The Board's Cost of Capital Report[12] identifies the elements to ascertain a fair return standard. The Report on page 18 states:

A fair or reasonable return on capital should:

- be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

[11] Report of the Board on Cost of Capital and 2^{nd} Generation Incentive Regulation for Ontario's Electricity Distributors, December 20, 2006

[12] Report of the Board on Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084

NRG has provided no evidence that a 9.85% ROE will impact the organization adversely. In fact, at the oral hearing, NRG considered itself to be a stronger utility and provided evidence to its financial viability. NRG referred to the Union Cessation of Service Proceeding and specifically noted that it had never missed a payment to Union. NRG has presented no evidence that its financial viability would be at risk if it receives the Board recommended Cost of Capital. In fact at the oral hearing NRG's witness noted that the asset base had increased substantially and the debt was being reduced aggressively[13].

Although NRG has added the IGPC pipeline, NRG did not face any difficulty in raising the significant amount of capital required to construct the project. There is no evidence to suggest that NRG's lender will change its position if NRG received an ROE that is lower than requested. With respect to equity, NRG has already indicated that the shareholder does not intend injecting any further equity and this was not dependant on the return that is provided. The shareholder has also not provided any evidence that the invested capital can provide a greater return elsewhere with a similar risk profile.

Although NRG has referred to the fair return standard, it has provided no evidence or demonstration how the Board's use of the Cost of Capital parameters will adversely impact NRG or impinge on the fair return standard.

Cost of Debt

The debt portfolio of NRG consists of three components: a fixed rate loan, which will be renewed in March 2011, a variable rate loan and a revolving line of credit that is not being utilized. The long-term debt cost of 6.69% reflects a 7.52% interest rate on one of the Bank of Nova Scotia loans, the forecast rate of 4.10% on the other Bank of Nova Scotia loans, plus amortization costs related to the refinancing of previous debt as directed in the NRG 2007 rates case decision (EB-2005-0544). In addition, NRG maintains a compensating balance of $2.75 million in the form of a Guaranteed Investment Certificate ("GIC") with the Bank of Nova Scotia. The amount has been borrowed for the purposes of investing in the GIC.

Board staff submitted that by removing the compensating balance, NRG was using a fairly unusual method to calculate the cost of capital. Although NRG was paying a total rate of 6.69% on its long-term debt, the rate that it was seeking to recover from

[13] Oral Hearing Transcript, Volume 3, page 91 (lines 2-6)

ratepayers was 8.26%. Board staff noted that NRG was seeking to recover its actual cost of debt ($662,642) rather than the interest rate. Board staff submitted that NRG would benefit under this methodology as it obtains a higher interest rate on its debt which actually forms a much larger portion of the capital structure but is lowered by the compensating balance. Board staff therefore submitted that NRG should be allowed a rate of 6.69% on the debt portion of the deemed capital structure.

The arguments of Board staff were echoed by all other intervenors. VECC submitted that the GIC was not a specific requirement imposed by the Bank of Nova Scotia as a prerequisite to obtain funding. In fact, the GIC was considered by NRG as an alternative to meet one of the covenants imposed on it by the Bank. VECC submitted that ratepayers should not bear the cost of NRG borrowing an additional $2.75 million for the sole purpose of creating an asset to balance its books as a result of a failure to maintain an adequate amount of actual equity in the company.

VECC submitted that Board deduct the amount of the GIC from the principal owed on the fixed rate loan (7.55%) and then recalculate the effective cost of debt. Using this methodology, VECC submitted that the long-term debt rate for the 56% long term debt component of NRG's capital structure should be 6.36% for the Test Year.
The argument put forth by VECC was adopted by the Town and IGPC.

In Reply, NRG submitted that if the rate proposed by Board staff and intervenors was accepted then it would not be able to recover its actual interest expense which was an unreasonable outcome. NRG argued that the compensating balance was required to maintain the covenants of the utility's loan arrangements. NRG submitted that maintaining a good working relationship with its lender was in the best interests of NRG and its ratepayers.

VECC also made a submission on the short term debt portion. In its Application, NRG used a notional amount of short term debt to fill the gap between its deemed amount of long term debt and its deemed amount of equity. The rate applied by NRG to the notional amount of short term debt is 0.5%. VECC submitted that the Board should order NRG to use a rate of 2.07% for the short term debt component in accordance with the Cost of Capital Parameters issued by the Board on February 24, 2010.

Board Findings

NRG has used a novel method to reduce its debt and increase the equity by using a compensating balance in the form of a GIC. This has resulted in a lower debt ratio and a higher interest rate than actual as NRG tries to recover its actual interest cost.

In addition, the evidence in the proceeding indicates that the requirement to hold a compensating balance is not a requirement of the Bank but is an NRG-devised approach to meet one of the covenants of the loan agreement. NRG did not explore other alternatives and considered using a compensating balance as a suitable technique to meet its loan obligations and maintain a good working relationship with the bank.

It is not known whether NRG could have obtained a better rate or relaxed covenants through a different financial institution. The Board also recognizes the fact that NRG had to significantly increase its debt portfolio to meet its financial commitments related to construction of the IGPC pipeline. At the same time, the Board recognizes that the use of a compensating balance is unusual and there is no evidence suggesting that it will be required on an ongoing basis.

The Board has determined that it will deduct the value of the GIC from the principal of the variable rate loan to calculate the blended cost of long term debt. The resulting cost is 7.67%.

Long-Term Debt	Average Principal	Cost Rate	Carrying Cost
Refinancing Cost Amortization			49,814
BNS Variable Rate Loan	3,943,333	4.12%	162,565
BNS Fixed Rate Loan	5,964,863	7.55%	450,263
GIC (assumed cost of variable rate loan)	-2,751,130	4.12%	-113,347
	7,157,066	**7.67%**	549,295

The short-term debt rate will be in accordance with the Board's 2010 Cost of Capital Parameters. The Board's decision on NRG's Cost of Capital is summarized below:

Average Cost of Capital

Description	Ratio	Cost Rate	Weighted Avg.
Long Term Debt	56.00%	7.67%	4.30%
Short Term Debt	4.00%	2.07%	0.08%
Common Equity	40.00%	9.85%	3.94%
Total	100.00%		8.32%

COST ALLOCATION

NRG has added a new rate class (Rate 6) to allocate appropriate costs to its largest customer, IGPC. NRG has proposed certain changes to its existing cost allocation model in order to accommodate the new rate class. The proposed cost allocation model allocates certain costs that are directly assignable to IGPC. In addition, NRG has allocated a share of common costs to IGPC.
During the oral hearing, NRG was asked to consider refinements to the cost allocation model to appropriately reflect allocation to the Rate 6 customer class, specifically allocation of insurance costs.

The submissions largely focused on appropriate allocation of insurance costs. In its Application, NRG proposed to recover $221,330 out of the total insurance cost of $284,925 from IGPC. Pursuant to Undertaking J2.6, NRG reduced the amount to $173,067. This was as a result of a letter from NRG's insurance provider, Zurich Global Energy that provided a risk factor of 40% for exposure to the IGPC pipeline.

IGPC in its submission argued that the letter from Zurich did not provide sufficient detail and did not identify the specific components of insurance that the 40% applied to. Considering that Zurich did not provide further details on the 40% allocation, IGPC submitted that it should be allocated 40% of all the insurance coverage as compared to 100% for some of the insurance costs. Additionally, it identified specific elements of the coverage that it did not accept as reasonable.

Transfer Station Insurance

NRG has allocated 100% of the transfer station insurance costs to IGPC. IGPC submitted that it failed to understand the expenditure of $35,387 to insure a station that costs $884,003 for an amount of $1,785,000.

Property, Plant and Equipment Insurance

Since maintenance of the IGPC pipeline is proposed to be subcontracted to a third party, IGPC was of the opinion that no equipment floater and fleet insurance costs should be allocated to IGPC.

Summarizing its position, IGPC recalculated the insurance costs and the allocation to IGPC. The revised calculation excludes business interruption insurance and allocates 40% to IGPC for all the other insurance costs. The resulting allocation reduces IGPC's share of the insurance costs, from $173,067 to $103,738. IGPC claimed that despite its proposed adjustment, the insurance costs for other rate classes would decline by 14% as compared to 2008, from $180,651 to $155,608.

VECC in its submission agreed with the allocation of administrative and general expenses to Rate 6. With respect to allocation of insurance costs, VECC indicated that the letter from Zurich Global Energy was vague and provided little or no guidance to the Board. VECC was therefore unable to recommend or reject the proposed allocations of the company wide general and umbrella liability costs to IGPC.

VECC however noted that in cases where the new policies are caused by the addition of IGPC as a customer, the proposed allocation of 100% to that customer sounds reasonable. Accordingly, VECC submitted that if the Board were to find the costs to be prudent then the transfer station insurance costs, business interruption insurance and the additional umbrella liability coverage should be 100% allocated to IGPC.

The Town and IGPC also submitted that the Board should require NRG to conduct a comprehensive cost allocation study for approval in its next cost of service rate application.

In Reply NRG agreed with VECC that the letter from Zurich did not provide sufficient rationale or basis for its determination. However, NRG indicated that this was the best available estimate.

Board Findings

The Board agrees with VECC that evidence to determine the appropriate allocation of insurance costs to IGPC is lacking. The only number before the Board is the 40% recommended by Zurich Global Energy. The Board will accept the 40% allocation of insurance costs as it is the best available evidence on the question in this proceeding. As a result of the Board's determination on business interruption insurance, IGPC will be allocated $147,487 in insurance costs.

With respect to conducting a review of the cost allocation methodology, the Board is of the opinion that as NRG gains experience of managing its operations with the addition of a new rate class, it will have better information on how IGPC impacts its costs. The question of whether NRG should conduct a review of its cost allocation methodology will be addressed in the next cost of service proceeding. By that time NRG will have better data and understanding of how the rate classes impact its cost structure. In the interim, NRG is directed to ensure that it retains all information relevant to this issue.

EFFECTIVE DATE

NRG is seeking rates effective October 1, 2010. Its current rates were declared interim on September 9, 2010. The Board approves an effective date of October 1, 2010 and the recovery of the revenue shortfall arising in the period between October 1, 2010 and the implementation of the new rates.

The Board has made findings in this Decision which change the revenue deficiency and therefore the proposed 2011 distribution rates. These are to be properly reflected in a Draft Rate Order incorporating an effective date of October 1, 2010 for the new rates.

In filing its Draft Rate Order, the Board expects NRG to file detailed supporting material, including all relevant calculations showing the impact of this Decision on NRG's proposed revenue requirement, the allocation of the approved revenue requirement to the classes, the variance account rate riders and the determination of the final rates, including bill impacts. NRG is also directed to file an accounting order related to the new deferral and variance accounts established in this Decision.

A Rate Order and a separate cost awards decision will be issued after the processes set out below are completed. The Board also expects NRG to file Phase 2 of the proceeding that deals with IRM and other matters identified in this Decision by March 2011.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

All filings with the Board must quote the file number EB-2010-0018, and be made through the Board's web portal at www.errr.oeb.gov.on.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.oeb.gov.on.ca. If the web portal is not available you may e-mail your documents to the attention of the Board Secretary at BoardSec@oeb.gov.on.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

THE BOARD ORDERS THAT:

1. NRG shall file with the Board, and shall also forward to IGPC, VECC, Union and the Town (collectively, "The Intervenors") a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 21 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. The Draft Rate Order shall also include accounting orders related to three new deferral accounts: IFRS Deferral Account, IGPC Pipeline Maintenance Deferral Account and the Transportation Revenue Deferral Account.

3. The intervenors shall file any comments on the Draft Rate Order with the Board and forward to NRG within 12 days of the filing of the Draft Rate Order.

4. NRG shall file with the Board and forward to the intervenors responses to any comments on its Draft Rate Order within 5 days of the receipt of any submissions.

5. The intervenors shall file with the Board and forward to NRG, their respective cost claims within 40 days from the date of this Decision.

6. NRG shall file with the Board and forward to the intervenors any objections to the claimed costs within 45 days from the date of this Decision.

7. The intervenors shall file with the Board and forward to NRG any responses to any objections for cost claims within 50 days of the date of this Decision.

8. NRG shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, December 6, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2010-0018

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas and other discrete issues.

BEFORE: Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

DECISION AND ORDER – PHASE 2
May 17, 2012

Natural Resource Gas Limited ("NRG" or the "Applicant"), filed an application dated February 10, 2010 with the Ontario Energy Board under section 36 of the *Ontario Energy Board Act*, *1998,* S.O. c.15, for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the 2011 fiscal year, commencing October 1, 2010.

NRG is a privately owned utility that sells and distributes natural gas within Southern Ontario. The utility supplies natural gas to Aylmer and surrounding areas to approximately 7,000 customers with its service territory stretching from south of Highway 401 to the shores of Lake Erie, from Port Bruce to Clear Creek.

The Board issued a Notice of Application dated March 1, 2010. The Town of Aylmer, Union Gas Limited ("Union"), Integrated Grain Processors Co-Operative Inc. ("IGPC") and Vulnerable Energy Consumers Coalition ("VECC") applied for and were granted intervenor status.

The Board issued a decision and order on December 6, 2010 that determined rates for the 2011 rate year (effective October 1, 2010). The Board also accepted NRG's request to address the IRM component of the Application for 2012 and beyond (and certain other discrete issues) in a second phase to the proceeding ("Phase 2").

Phase 2 Proceeding

NRG filed a revised IRM plan on May 6, 2011 that adopted the same architecture as the Board's 3rd Generation Incentive Rate Mechanism for electricity distributors in Ontario.

In addition, on July 18, 2011, NRG completed its Phase 2 filing requirements by filing an independent system integrity study that identified alternatives to maintaining system pressure in NRG's southern service area as opposed to purchasing gas from the related company, NRG Corp.

A settlement conference was held on September 26, 2011. A settlement agreement was reached on two of the three issues before the Board in Phase 2; the price for gas purchased from NRG Corp. (a related company) remained unsettled. NRG filed a settlement agreement on November 11, 2011. The Board accepted the settlement agreement at the oral hearing held on November 30, 2011.

In addition, on June 7, 2011, IGPC filed a letter requesting the Board to hear a motion (the "Motion") that it had filed on August 3, 2010 related to its dispute over the construction costs of the pipeline built by NRG to serve the IGPC ethanol plant. At the oral hearing in the first phase of the proceeding, the Board determined that its decision would only address issues that had potential rate impacts. The Board indicated at that time that IGPC would be free to recast its Motion on the remaining issues should there be any at a later date.

NRG filed a letter on June 22, 2011 submitting that the Board in its Decision of December 6, 2010 had already determined the capital cost of the IGPC pipeline and that the Board did not have jurisdiction to revisit the issue. NRG maintained that if IGPC believed that there were issues remaining in the motion then it needed to recast the motion and file the relevant materials.

In a letter filed on July 6, 2010, IGPC clarified the elements of its Motion that were, in IGPC's view, still outstanding. IGPC submitted that the capital cost of the pipeline was still in dispute and before the Board in the Motion filed by IGPC. The specific items listed by IGPC include; (i) the administrative penalty; (ii) NRG's claimed legal costs; (iii) the costs claimed in respect of Mr. Mark Bristoll; and (iv) interest and other costs.

In Procedural Order No. 7, the Board invited submissions from parties on whether the matters raised in the Motion are properly before the Board. IGPC, Board staff and NRG filed submissions on the revised Motion. IGPC filed a supplemental submission on August 19, 2011 in response to the submission made by Board staff and NRG. The Board accepted the supplemental submission of IGPC but provided NRG an opportunity to file a response if needed.

The two remaining issues before the Board in Phase 2 of the proceeding are the cost of gas purchased from NRG Corp. and the Revised Motion brought forward by IGPC.

Cost of Gas Purchased from NRG Corp.

NRG has purchased natural gas from NRG Corp., a related company for over 30 years. During that time, NRG's system has expanded significantly, from essentially a gathering system for local production to a gas utility serving more than 7,000 customers.

NRG Corp. has approximately 41 wells serving NRG and, according to the Argument-in-Chief, NRG Corp. has been drilling its wells and bringing on production for the sole purpose of supplying gas to NRG Distribution Ltd[1]. NRG has argued that this arrangement has worked well for ratepayers and if NRG had not had local supply from NRG Corp., NRG's system customers would have collectively paid an extra $2 million for gas from fiscal 2007 to 2011[2].

[1] NRG Argument-in-Chief December 23, 2011, page 10
[2] NRG Argument-in-Chief December 23, 2011, page 13

NRG has pointed to other benefits of sourcing local gas including reduced charges from Union Gas Limited as a result of requiring less gas at its interconnecting points with Union Gas Limited and lower distribution rates resulting from the avoidance of costly capital additions to supply gas to NRG's southern service area. The second benefit comes from a study undertaken by NRG to identify alternatives to buying gas from NRG Corp. while maintaining system pressure within the southern distribution area.
NRG argues that, because of the manner in which its system was developed over time, it can have system pressure issues in the southern part of its service territory on days where demand for gas is particularly high. NRG maintains that the best way to address this issue is to continue to use locally produced gas (in particular that provided by NRG Corp.), as it feeds into the system closer to the problem areas.

The study presented three alternatives to purchasing gas from NRG Corp. All alternatives recommended the construction of a new pipeline of varying lengths with costs ranging from $8 million to $23 million. NRG has estimated the new pipeline costs to be in the range of $200 per customer and it is in this context that NRG believes that purchasing gas from the related company at a premium represents a good deal for customers.

NRG has proposed that it be permitted to buy gas at $8.486 per mcf from NRG Corp. whenever the market price for natural gas is $9.999 per mcf or less, and to pay the market price when natural gas is $10.00 per mcf or more.

Board staff in its submission argued that the price of $8.486 is significantly higher than the current market price and NRG has offered limited evidence of how this premium benefits ratepayers.

Board staff further argued that the system integrity study did not look at all alternatives. There was no discussion with Union Gas on how they could assist in resolving the issue. Board staff argued that a new interconnect with Union in the area experiencing the problem in the simulation might resolve the issue. The study also did not examine the volumes required to maintain system integrity. This made it difficult for the Board according to Board staff to understand the magnitude of the issue and for other potential suppliers to know if they could alleviate the problem.

Board staff further pointed out an apparent conflict of interest that NRG Corp. had in finding other potential suppliers. NRG Corp. confirmed at the hearing that NRG Ltd. does not possess the expertise to source gas and it is NRG Corp. that performs this activity on behalf of NRG Ltd[3]. Board staff was of the opinion that it was not in the best interest of NRG Corp. to source gas from other suppliers for NRG Ltd. when it is in the business of selling gas itself. Board staff submitted that in such circumstances the Board should be cautious in allowing for payment of anything more than a market price for gas, and that the onus for establishing a different price rests firmly with NRG.

The second concern expressed by Board staff was that NRG had made no serious attempt to look for other possible local gas providers in the area. Mr. Graat who as an officer of NRG Corp. is a competitor with other local suppliers, indicated at the hearing that he considered all other suppliers as being unreliable and unable to provide gas on a consistent basis[4].

In light of the above arguments, Board staff submitted that NRG had not sufficiently demonstrated that a price floor for gas from NRG Corp. was the most effective solution to the system integrity issue.

Board staff offered the following recommendations in its submission:

1. To conduct another independent study under the supervision of intervenors (such as an intervenor steering committee) that could assist in developing the scope of the study. The study should conduct a detailed examination of the NRG system, the Union interconnects, local producers within the area and the amount of gas required to maintain system integrity on a daily/weekly/monthly basis.

2. To order NRG to request quotes from all suppliers within the area that are willing to commit to providing the required quantities of gas. NRG Corp. indicated that some producers have shut their gas because of low prices[5]. The Board could allow a premium over the market price (for example: a 10% to 15% premium) in the RFQ considering that it is fulfilling peak demand and this could incite other

[3] Transcript Phase 2, Volume 1, page 51
[4] Transcript Phase 2, Volume 1, pages 53 and 118
[5] Transcript Phase 2, Volume 1, page 136

dormant producers within the area to respond to the request. This premium would still be significantly lower than that proposed by NRG Corp.

3. To keep in place the current maximum of 2.4 million cubic meters representing system integrity gas.

VECC in its submission noted the unusual situation where the sole buyer for NRG Corp.'s gas is a related utility and the gas is being sold at a premium. VECC submitted that it is inappropriate to set floor prices ($8.486 per mcf) that should be paid by a utility to an unregulated related party that guarantees up to a point a premium above market prices. VECC further submitted that the negotiations between NRG Ltd. and NRG Corp. appear to have been dominated by NRG Corp.'s take-it-or-leave-it offer, with the utility having little latitude in the talks. VECC was of the opinion that the floor price was indicative of market power, exercised by a dominant or a critical supplier.

VECC submitted that there was no evidence to substantiate that it was not in the best financial interest of NRG Corp. to sell below the floor price and in that case a market-based methodology was more appropriate. VECC supported the position of Board staff that in the absence of an RFP process, the Board should continue with the current Board approved pricing methodology. VECC also supported Board staff recommendations of another independent engineering study that included a more robust sensitivity analysis and an independent RFP process that included other potential suppliers within NRG's franchise area.

In Reply, NRG dismissed the suggestions of Board staff and VECC to undertake an additional engineering study to consider other technical and physical options to solve the system integrity issue, and ordering NRG to put out an RFP to solicit additional sources of gas supply. NRG submitted that the only issue that needs to be resolved by the Board is the pricing methodology governing gas commodity purchases from NRG Corp. NRG further submitted that the Board should determine a pricing methodology that should stay in place until NRG's next cost of service proceeding.

NRG submitted that Board staff and VECC were suggesting ways to ensure that NRG does not have to buy gas from NRG Corp. NRG clarified that it plans to continue to buy gas from NRG Corp. because it makes good sense for NRG and its ratepayers. NRG did not consider buying gas from NRG Corp. as a problem and it submitted that it did not make sense to spend a significant amount of time and money to come up with alternatives to buying gas from NRG Corp. NRG submitted that the actual issue was fairly narrow and centered around determining an appropriate pricing methodology.

NRG pointed to several benefits of purchasing gas from NRG Corp. which included a guaranteed local supply, reduced charges from Union Gas, avoidance of costly capital additions and lower gas commodity costs as compared to gas from third parties.

NRG further submitted that the study completed by Aecon Utility Engineering was complete and the terms of reference were approved by the Board prior to initiating the study. NRG submitted that although there could be other alternatives and scenarios to examine, at some point the cost of studying the system integrity issue would outweigh the benefits. NRG indicated that irrespective of there being a system integrity issue, it still made sense for NRG to buy gas from NRG Corp. NRG claimed that it is almost impossible to determine a single amount of system integrity gas that is required given that the system is fairly dynamic.

NRG in Reply refuted Board staff's suggestion that Union Gas could provide a solution. NRG pointed to the hearing transcript in which Mr. Graat confirmed that the problem was not getting gas from Union but distributing it in the franchise area[6].

NRG dismissed the recommendations of Board staff and VECC for seeking alternative suppliers within the area for the simple reason that there were no real acceptable supply prospects in the area. NRG submitted that any RFP ordered by the Board would have to contain numerous conditions including that potential suppliers would need to have wells in the problem area, namely, NRG's southern service area. Potential suppliers would need to build and pay for pipelines to connect to NRG's distribution system and would have to be prepared to enter into a contract with no fixed quantity and be able to supply on demand. NRG further indicated that potential suppliers would need to provide some form of security such as a letter of credit or performance bond to ensure delivery under the contract.

[6] Transcript Phase 2, Volume 1, pg. 50

NRG in Reply reiterated its firm belief that there are no acceptable suppliers that would agree to or be able to supply on such conditions. NRG therefore submitted that the Board should reject the arguments of Board staff and VECC with respect to an additional engineering study and an RFP and adopt the pricing proposal of NRG.

Board Findings

Although NRG Ltd. and NRG Corp. are not technically affiliates as defined in the Board's Affiliate Relationships Code, they share a very close relationship. Mr. Graat is a controlling officer of both companies and this makes NRG Ltd. in effect a vertically integrated utility. NRG buys a portion of its gas supply needs from NRG Corp. and as the evidence as it currently stands suggests that NRG apparently has few options to replace gas purchased from NRG Corp.

The issue before the Board is not so much the fact that it is inappropriate to purchase gas from a related company but rather that the pricing mechanism being sought by NRG seems to demonstrate that NRG Corp. exercises market power within the utility's franchise area. Gas prices are at historical lows and NRG Corp. is unwilling to sell gas at market rates. In fact, NRG Corp. has testified that it is unwilling to sell below the requested rate of $8.486 per mcf and will suspend production if it was asked to sell at market rates. This means that NRG ratepayers could face a situation where supply is suspended and gas not being available in certain areas or in required quantities. The Board is concerned that NRG's customers could face a potential shutdown of services or if service is provided, customers would pay significantly higher than market rates for what could be a material portion of their gas supply.

The evidence indicates that there has been a contract between NRG and NRG Corp, although there does not seem to be an executed copy for the current time period.

Furthermore, under the terms of the agreement, NRG Corp. is not obligated to provide gas to the utility and the contractual obligation can best be described as ambiguous. NRG has testified that it needs gas from NRG Corp. to maintain system integrity and the report submitted by NRG shows that the pressure could drop to unacceptable levels in the southern service area if NRG Corp. wells were shut off on a very cold day (-28 degrees Celsius).

The study however did not identify the volume of gas that is required to maintain system integrity and accordingly system integrity demand is largely theoretical at this stage. In fact, NRG stated in Reply that it is impossible to precisely define a single amount of system integrity gas that is required. Notwithstanding that, NRG is seeking a firm rate of $8.486 per mcf for all gas purchased from NRG Corp, and asks that there be no cap on how much gas NRG can purchase from NRG Corp. at this price.

The issue before the Board is fairly complex and may require a two-step process before a long term resolution emerges. In the meantime, customers will require a reliable supply and an interim solution is required.

NRG has estimated 2.4 million cubic meters as system integrity gas. There is no evidentiary basis for this estimate and the system integrity study has been unable to confirm this number. However, in response to an undertaking[7], Mr. Chan of Aecon Utility Engineering has provided a broad range for the number of customers that could potentially lose service should the temperature dip to -28 degree Celsius and all NRG Corp. wells are shut off. The estimate varies between 300 and 3,000.

The Board believes that the number of 2.4 million cubic meters is fairly high and considers 1.0 million cubic meters to better represent the demand related to system integrity. This number represents the approximate average annual demand of 5% (353) of NRG's Rate 1 customers, an approach that is at least somewhat consonant with the information appearing in the Aecon report.

The Board will allow NRG to recover from ratepayers a maximum annual quantity of 1.0 million cubic meters of natural gas at the rate of 8.486 per mcf. Any additional quantities beyond 1.0 million cubic meters that are purchased from NRG Corp. would only be eligible for recovery from ratepayers at current market rates that would be determined quarterly as per the methodology outlined in the Board's Decision of December 6, 2010.

[7] Undertaking J1.3

The Board is aware that there are several potential suppliers in the franchise area of NRG. The argument of NRG that other potential suppliers will not be able to fulfill the requirements of its system has not been adequately demonstrated, and there is little evidentiary basis to support it. The interest of NRG's ratepayers must be protected where a related company seeks a significant premium to current market rates to supply the commodity and, at least in part, meet its own expansion plans. In addition, the Board does not have any financial information regarding NRG Corp. that demonstrates that the price that it is seeking represents a fair price for NRG customers. The Board is not necessarily opposed to NRG purchasing gas from NRG Corp. The issue is the nature, scope and extent of the premium that ratepayers are being asked to bear for this purchase option.

Board staff and VECC have recommended procurement of an independent study that would look at all relevant alternatives and conduct a more robust sensitivity analysis. The Board sees merit in this recommendation.

Accordingly, the Board will require the formation of a steering committee comprised of Board staff, intervenors and NRG that will be responsible for drafting an RFP and terms of reference for an independent study, the findings of which will be presented to the Board.

The Board invites all intervenors to be a part of the steering committee. Reasonable costs of participation, consistent with the Board's *Practice Direction on Cost Awards* will be recoverable. The committee will be responsible for selecting an independent consultant and providing directions to the consultant as to the scope of the study and the deliverables. NRG must make itself available for the committee meetings and provide all of the required data and assistance that the consultant may require.

The Board expects the study to look at the technical and engineering aspects of NRG's system and arrive at firm conclusions with respect to the amount of system integrity gas that NRG may require under different scenarios, including, but not limited to a single design day. The Board also expects the consultant to review the gas supply available within NRG's franchise area and provide an analysis on whether a competitive market can exist within NRG's franchise area and if so, the mechanics of establishing such a market. This includes identifying other potential suppliers within the area and determining if they can be a viable and reliable supply option. The study could also examine if the Union Gas system could provide any cost effective solutions. The cost of the study will be borne by ratepayers. The resulting report will be filed with the Board no later than **September 30, 2012**. If for some reason the consultant chosen to prepare the report is unable to do so within this timeframe, the panel can be petitioned to extend it. The Board, as part of this direction approves the creation of a deferral account to capture the costs associated with the study.

Based on the recommendations of the study, the Board may order NRG to issue an RFP that would solicit alternative suppliers within the NRG franchise area.

IGPC Revised Motion

In the Revised Motion IGPC claims that the actual total cost of the pipeline has still not been directly addressed by the Board. The specific items that IGPC believes have yet to be determined include: (i) the administrative penalty; (ii) NRG's claimed legal costs; (iii) the costs claimed in respect of Mr. Mark Bristoll; and (iv) interest and other costs.

The Board sought submissions on the Recast Motion. Board staff, NRG and IGPC filed submissions.

Board staff in its submission referred to Article IX of the Pipeline Cost Recovery Agreement ("PCRA") which states on page 17:

ARTICLE IX – DISPUTE RESOLUTION

9.1 In the event of any dispute arising between the Parties regarding the subject matter of this Agreement, then the parties shall negotiate in good faith to resolve such matters.

9.2 In the event the Parties are unable to resolve a dispute, then either Party may refer to the matter to the OEB for resolution.

Board staff submitted that neither IGPC nor NRG appear to have consulted with the Board regarding the Board's proposed role of dispute arbitrator, nor was the Board aware of this provision until the PCRA was filed with the Board after it had been executed.

Board staff submitted that the Board is a quasi-judicial regulatory tribunal. Its powers, like those of all tribunals, are granted through legislation. The Board can only act in accordance with those powers specifically provided by legislation, either directly or through the doctrine of necessary implication. The Board has no legislative authority to act as an arbitrator for contractual disputes, and no provision in a contract (such as Article IX to the PCRA) can give the Board such a power. To a certain degree, the Board has already acted to resolve this dispute by determining the appropriate costs of the pipeline for ratemaking purposes. However, the Board has no further statutory powers to resolve the remaining issues concerning the total costs of the pipeline. Board staff therefore submitted that the Board should decline the invitation to act as an arbitrator.

Section 11.2(b) of the PCRA indicates that the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of this agreement. Board staff in its submission suggested that to the extent the parties cannot come to an agreement on the total cost of the pipeline, the courts are the appropriate forum in which this dispute should be resolved.

Contrary to Board staff's submission, IGPC was of the view that the Board did have jurisdiction to determine the issues that were raised in the Motion. IGPC submitted that the powers of the Board were fairly broad and pursuant to section 19(6) of the OEB Act, the Board has exclusive authority over matters within its jurisdiction. IGPC submitted that where a capital expenditure is required by the utility for the distribution of natural gas, the process includes the potential for a one-time payment in the form of a contribution in aid of construction, combined with a series of periodic payments. IGPC submitted that a utility cannot escape regulatory oversight and charge rates that are not just and reasonable by forcing a customer to pay a contribution in aid of construction relating to unreasonable and imprudently incurred costs.

In reviewing the actual capital expenditures of NRG, IGPC submitted that certain of the expenditures claimed by NRG were imprudent and unreasonable. IGPC was thus owed a refund by NRG.

IGPC quoted Part VII.1 of the OEB Act that provides the Board with the authority to take steps to remedy the contravention, or potential contravention of an enforceable provision. IGPC submitted that in the current context, NRG had failed to fulfill the requirements of the charges it was authorized to impose and has thereby contravened an enforceable provision within the meaning of the OEB Act.

Rejecting the submission of Board staff, IGPC submitted that Board staff's position was discriminatory as it permits consumers who do not pay a contribution in aid of construction to be able to review all capital expenditures related to their project whereas consumers that pay a contribution in aid of construction are limited with respect to capital expenditures that can be reviewed (those costs that only impact rates).

IGPC further noted that Article IX of the PCRA not only appointed the Board as an arbitrator but more importantly recognized the role of the Board as the industry regulator.

NRG in its submission quoted the PCRA that confirms that the courts of Ontario have exclusive jurisdiction to determine all disputes arising out of the agreement between NRG and IGPC. Section 11(2)(b) of the PCRA states:

> 11.2 This Agreement
>
> *(b) shall be construed and enforced in accordance with, and the rights of the parties shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein, and the courts of Ontario shall have exclusive jurisdiction to determine all dispute arising out of this Agreement;*

NRG referred to the 2004 Supreme Court of Canada decision, *Garland v. Consumers' Gas Co.* [2004] 1 S.C.R. 629, that was a class proceeding started in 1994 by the plaintiff against Consumers' Gas Company Limited ("Consumers"). The plaintiff sought a restitutionary payment of $112 million, representing late payment penalties ("LPPs") paid by over 500,000 of Consumers' customers since 1981. The plaintiff also sought declaratory relief that the LPPs charged contravened s. 347 of the Criminal Code and need not be paid by the proposed plaintiff class. The rates and payment policies including the late penalty payments were governed by the Board.

Chief Justice McMurtry of the Ontario Court of Appeal noted that the restitutionary issue arising from the receipt of LPPs by Consumers for the past twenty years was an issue over which the courts have jurisdiction. He further added that the Board's jurisdiction to fix rates for gas and to set penalties for late payment does not empower it to impose a restitutionary order of the type sought by the plaintiff. Justice Iacobucci writing for a majority of the Supreme Court adopted the findings of the Court of Appeal and noted that although the dispute involved rate orders, the primary issue here was a private law matter suited to civil courts and the Board did not have jurisdiction to order the remedy sought by the plaintiff.

NRG cited this case and noted that the Supreme Court was very clear that the disputed issues are private law matters and the Board does not have jurisdiction to hear them. NRG also supported the arguments made by Board staff which noted that many of the issues in IGPC's Motion were beyond the purview of the Board.

Based on the above arguments, NRG submitted that the matters raised in IGPC's Motion were not properly before the Board.

Board Findings

The Board has already determined the rates for NRG and as part of that process addressed many of the issues raised by IGPC.

The Board substantially agrees with the submissions of Board Staff on this issue.

The Board can only act in accordance with those powers specifically provided by legislation, either directly or through the doctrine of necessary implication. The Board has no legislative authority to act as an arbitrator for contractual disputes, and no provision in a contract (such as Article IX to the PCRA) can give the Board such a power. The Board has no further statutory powers to resolve the remaining issues concerning the total costs of the pipeline.

Section 11.2(b) of the PCRA indicates that the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of this agreement. Board staff in its submission suggested that to the extent the parties cannot come to an agreement on the total cost of the pipeline, the courts are the appropriate forum in which this dispute should be resolved.

IGPC is seeking a refund. The issue between IGPC and NRG is essentially a contractual dispute between two private entities. The Board does not have jurisdiction to consider or remedy contractual disputes.

DATED at Toronto May 17, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

COURT FILE NO.: 273/07
DATE: 20080516

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ONTARIO
SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

KITELEY, CUMMING, AND SWINTON JJ.

B E T W E E N:	
ADVOCACY CENTRE FOR TENANTS-ONTARIO and INCOME SECURITY ADVOCACY CENTRE on behalf of LOW-INCOME ENERGY NETWORK	***Paul Manning*** and ***Mary Truemner***, for the Appellant
Appellant	
- and -	
ONTARIO ENERGY BOARD	***Michael Miller***, for Ontario Energy Board
	Fred Cass and ***David Stevens,*** for Enbridge Gas Distribution Inc.
Respondent	
	Robert Warren, for Consumers Council of Canada
	HEARD at Toronto: February 25, 2008

KITELEY and CUMMING JJ.

The Appeal

[1] The Respondent Ontario Energy Board (the "Board") is the provincial economic regulator for the natural gas and electricity sectors. The Board exercises its jurisdiction within the statutory authority established by the Legislature, being the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "*Act*").

[2] By a majority (2:1) decision dated April 26, 2007, the Board determined that the *Act* does not explicitly grant to the Board jurisdiction to order the implementation of a low income affordability program: *Enbridge Gas Distribution Inc.* (April 26, 2007), EB-2006-0034 (Ont. Energy Bd.) (the "Board Decision"). The Board also found that the Board does not gain the requisite jurisdiction through the doctrine of necessary implication.

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[3] Enbridge Gas Distribution Inc. ("EGD") sought approval by the Board of EGD's 2007 gas distribution rates based simply upon the Board's traditional, standard "cost of service" rate-making principles. The Appellant Low Income Energy Network ("LIEN") had intervened in the application before the Board. LIEN argues that without a rate affordability program, the interests of low-income consumers are not protected. LIEN proposed that the Board accept as an issue in the EGD proceeding the following matter:

> Should the residential rate schedules for EGD include a rate affordability assistance program for low-income consumers? If so, how should such a program be funded? How should eligibility criteria be determined? How should levels of assistance be determined?

[4] LIEN seeks from the Board the introduction of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of the proposal of LIEN is that low income consumers (estimated to be about 18% of households in Ontario) should pay less for gas distribution services than other consumers. LIEN emphasizes that the supply of natural gas (or other source of energy) serves to meet basic human needs such as warmth from heating and the generation of power. Those who cannot afford to use natural gas as a source of energy may be placed at a significant disadvantage. LIEN submits that the Board can consider ability to pay in setting rates if it is necessary to meet broad public policy concerns. Access to an essential service is arguably such a concern. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest.

[5] The majority of the Board held that the LIEN proposal amounted to an income redistribution scheme. The Board noted that such a scheme would require a consumer rate class based upon income characteristics and would implicitly require subsidization of this new class by other rate classes. It is undisputed that a common, if not universal, historical feature of rate-making for a natural monopoly is the application of the same charges to all consumers within a given consumer classification based upon cost of service, that is, cost causality.

[6] Section 33 of the *Act* provides for an appeal to this Court on a question of law or jurisdiction. LIEN seeks a declaration that the Board has the jurisdiction to order a "rate affordability assistance program" for low income consumers of the utility, EGD, within its franchise areas as the distributor of natural gas.

[7] The position of EGD, the Board and the intervenor, the Consumers Council of Canada, is that LIEN's quite understandable and commendable concern is an issue of public policy to be dealt with by the Legislature and falls outside the jurisdiction of the Board.

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The Standard of Review

[8] The issue is whether the Board is correct in its determination that it does not have jurisdiction to implement a low income affordability program.

[9] There is common ground that the standard of review is correctness. That is, this Court will interpret the statutory grant of authority on the basis of its own opinion as to a statute's construction, rather than deferring to the Board's determination of the issue. A tribunal's determination that it has no jurisdiction will be set aside as a "wrongful declining of jurisdiction" if the Court is of the view that the tribunal's decision is wrong. Donald J.M. Brown and John M. Evans, *Judicial Review of Administrative Action in Canada*, looseleaf (Toronto: Canvasback Publishing, 1998) at 14-3 to 14-4.

Analysis of the Board's Jurisdiction

A. Applicable Principles

[10] The Court is to be guided by the principles of statutory interpretation as set forth in Ruth Sullivan, *Driedger on the Construction of Statutes*, 3rd ed., (Toronto: Butterworths, 1994) at 131:

> There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the legislation, the consequences of proposed interpretations, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just.

[11] The words of the *Act* are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme and object of the legislation and the Legislature's intent. *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37 [*Atco*].

[12] The statute shall be interpreted as being remedial and given such "fair, large and liberal interpretation as best ensures the attainment of its objects." *Legislation Act*, S.O. 2006, c. 21, Schedule F, s. 64 (1).

[13] A statutory administrative tribunal obtains its jurisdiction from two sources: explicit powers expressly granted by statute, and implicit powers by application of the common law doctrine of jurisdiction by necessary implication. *Atco*, *supra*, at para. 38.

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[14] The Court must apply a "pragmatic or functional" analysis in determining the issue of jurisdiction, by considering the wording of the *Act* conferring jurisdiction upon the Board, the purpose of the *Act* creating the Board, the reason for the Board's existence, the area of expertise of its members and the nature of the problem before the Board. *Union des employés de Service, local 298 v. Bibeault,* [1988] 2 S.C.R. 1048 at 1088.

B. The Wording of the Act

[15] Section 36 of the *Act* confers the Board's jurisdiction:

> **36.** (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.
>
> ….
>
> (2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.

[16] LIEN submits that the Board's authority to fix "just and reasonable rates" by adopting "any method or technique it considers appropriate", conferred by s. 36 (2) and (3) of the *Act* is very broad and the statutory language must be given its ordinary meaning.

[17] The Board argues that the word "rates" is in the plural form in s. 36 (2) to allow the Board to set different rates for different classes of consumers based upon the costs of serving those consumers. For example, large industrial users are typically considerably more expensive to serve than residential consumers. Separate rate classes are a necessity to ensure that consumers reimburse for the actual costs of the service they receive.

[18] The majority opinion in the Board Decision is of the view that the words "any method or technique" cannot reasonably be interpreted to mean "a fundamental replacement of the rate making process based on cost causality with one based on income level as a rate grouping determinant." (p.9)

[19] The phrase "approving or fixing just and reasonable rates" in the present s. 36 (2) was first introduced by s. 17 (1) of Bill 38, *An Act to Establish the Ontario Energy Board*, 1st Sess., 26th Leg., Ontario, 1960 by the then Minister of Energy Resources, the Hon. Robert Macaulay. He outlined for the Legislature the philosophy underlying rate setting (*Legislature of Ontario Debates*, 9 (8 February 1960) at 199 (Hon. Macaulay)):

> First, why are there rate controls? There are rate controls because, in effect, the distribution of natural gas is a monopoly, a public utility. Secondly…it is fair that whatever rate is charged should be one designated, not only in the interests of the consumer, but also in the interests of the distributor…[O]ne really should have in mind 3 basic objectives: First, the rate should be low enough to secure to the user a fair and just rate. Second, the rate should be adequate to pay for good service and replacement and retirement of the used portion of the assets. Third, it should be high enough to attract a sufficient return on capital….

[20] He went on to explain the purpose of the Government's policy (at 205):

> "[F]irst, to protect the consumer, and to see that he pays a fair and just rate, not more or less, and that is competitive with other fuels. Second, to make sure the rate is sufficient to provide adequate service, replacements and safety for the company providing the service. Third, it is that the company should be able to charge a rate which is sufficient to attract the necessary capital to expand.

[21] The present s.36 (3) replaced s.19 of the old *Ontario Energy Board Act*, R.S.O. 1980, c. 332, which required a traditional cost of service analysis in very prescriptive terms:

> 19 (2) In approving or fixing rates and other charges under subsection (1), the board shall determine a rate base for the transmitter, distributor or storage company, and shall determine whether the return on the rate base …is reasonable.
>
> The rate base …shall be the total of,
>
> (a) a reasonable allowance for the cost of the property that is used or useful in serving the public, less an amount considered adequate by the Board for depreciation, amortization and depletion;
>
> (b) a reasonable allowance for working capital; and
>
> (c) such other amounts as, in the opinion of the Board, ought to be included.

[22] The authority was granted in s. 36 (3) to use "any method or technique it considers appropriate" in approving "just and reasonable rates" i.e., employing methods other than simply on a traditional cost of service basis as proscribed in the repealed s. 19 to set rates for the gas sector. This aligned the approach for natural gas with the non-prescriptive authority seen governing Ontario Hydro as a Crown corporation in rate setting for electricity distributors.

[23] Thus, under the former *Act* the phrase "just and reasonable rates" was limited to the cost of service basis articulated in prescriptive detail in s. 19. The change in repealing s. 19 and allowing the Board to "adopt any method or technique it considers appropriate" provides greater flexibility to the Board to employ other methods of rate making in approving and fixing "just and

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reasonable rates" rather than simply the traditional cost of service regulation seen in the former s. 19.

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[24] Subsection 36 (3) allows the Board to adopt "any method or technique that it considers appropriate" in fixing "just and reasonable rates." The majority Board Decision view is that this provision, considered within the context of the *Act* as a whole, allows the Board to employ flexible techniques and methods for cost of service analyses in determining rates, for example, the incentive rate mechanisms currently used for the major gas utilities.

[25] In the same rate setting proceeding that is under review, EGD reportedly asked the Board to approve two fuel-switching programs to enable residential consumers to shift from electric-water heaters to gas-water heaters, given that the latter promote conservation inasmuch as there is greater energy efficiency. The programs are identical except that there is a subsidy offered for the low income group of $800 per participant but a subsidy of only $600 for other consumers. Vice Chair Kaiser in dissenting points out that none of the parties have objected to this proposal and no one has argued that the Board does not have jurisdiction to approve different subsidies based upon income levels.

[26] Indeed, the majority opinion in the Board Decision allows that the Board has ordered that specific funding be channeled aimed at low income consumers for "Demand Side Management Programs."

[27] As well, the Board on occasion has reduced a significant rate increase because of so-called "rate shock" by spreading the increase over a number of years. Although this does not in itself suggest an unequal approach as between residential consumers it does indicate that the Board considers it has jurisdiction to take "ability to pay" into account in rate setting.

[28] EGD, like other utilities, makes annual contributions to enable emergency financial relief through the so-called "Winter Warmth Program" which provides funds as a subsidy to some low income consumers, enabling them to be able to heat their homes in winter months. These subsidies are taken into account as costs of the utility in the approval and fixing of rates by the Board. Although the program is funded by all consumers, to some extent there is indirect cross-subsidization within the residential consumer class.

[29] The Board points out that this is a relatively small program in the nature of a charitable objective, involving the United Way, which is specific to individual consumers in a financial crisis situation. But the fact remains that its implementation means that some residential consumers are paying less for the distribution and purchase of natural gas than other residential consumers are paying. If the Board has jurisdiction to approve utilities paying subsidies to the benefit of low income consumers then it arguably has jurisdiction to order utilities to provide special rates on a low income basis.

[30] Section 79 of the *Act* explicitly authorizes the Board to provide rate protection for rural or remote consumers of an electricity distributor. The majority decision argues that it is a reasonable inference that the Legislature, by virtue of the explicit singling out of a single

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category of consumers in s. 79, did not intend this benefit to apply to other categories of consumers. The Board argues that if s. 36 (2) and (3) are intended to allow for differential rate setting for subsets of residential consumers, then s. 79 is unnecessary. The majority decision considers the existence of s. 79 as indicating that the Legislature has been explicit on issues that it considers warrant special treatment through a subsidy. The majority decision argues that the existence of s. 79 implicitly excludes any intent to confer jurisdiction to depart from simply the cost of service approach employed to implement the mandate given to the Board by s. 36.

[31] Moreover, the majority decision points out that rural rate assistance through s. 79 does not consider income level as an eligibility determinant. Rather, eligibility is based upon location and the inherent higher costs of service related to density levels. The assistance from the program is conferred upon all consumers within a given geographical area irrespective of their income level. Hence, this program arguably serves simply to mitigate the effect of the cost differential related to geography and remains consistent with a rate making process based upon cost causality. Nevertheless, "rate protection" through s. 79 operates as a subsidy paid by some of Ontario's residential electricity consumers for the benefit of others and represents a departure from the principle of cost causality being applied on the same basis to all consumers within a given class (i.e., residential, commercial and industrial).

[32] As pointed out in the dissent by Board Vice Chair Gordon Kaiser, s. 79 was introduced in 1999 when the authority to regulate rates for *electricity* distributors was transferred to the Ontario Energy Board. Prior thereto, electricity distributors were regulated by Ontario Hydro, a Crown corporation which had established the policy of setting special rates in remote and rural areas through the now repealed s. 108 of the *Power Corporation Act*, R.S.O. 1990, c. P. 18. The inference can be made, as Vice Chair Kaiser asserts, that s. 79 was introduced into the *Act* to expressly indicate to the Board that this significant historical policy must continue.

C. The Purpose of the Act and the Reason for the Board's existence

[33] The objectives for the Board with respect to natural gas regulation are set forth in s. 2 of the *Act*:

> (2) The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> 1. To facilitate competition in the sale of gas to users.
> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.
> 3. To facilitate rational expansion of transmission and distribution systems.
> 4. To facilitate rational development and safe operation of gas storage.
> 5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.

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> 5.1To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.
> 6. To promote communication within the gas industry and the education of consumers.

[34] The Board is charged under s. 2 of the *Act* with protecting "the interests of consumers with respect to prices …." The Board argues that this provision speaks to consumers as a single class, not to a particular subset of consumers. The majority decision of the Board says the Board's mandate is to balance the interests of consumers as a single group with the interests of the regulated utility in the setting of "just and reasonable rates."

[35] The Divisional Court has emphasized in the past that the Board's mandate to fix just and reasonable rates **"**is unconditioned by directed criteria and is broad; the board is expressly allowed to adopt any method it considers appropriate." *Natural Resource Gas Ltd. v Ontario Energy Board*, [2005] O.J. No. 1520 at para. 13 (Div. Ct.). The Divisional Court also stated in *Enbridge Gas Distribution Inc. v. Ontario Energy Board* (2005), 75 O.R. (3d) 72, [2005] O.J. No. 756 at para.24:

> …[T]he legislation involves economic regulation of energy resources, including setting prices for energy which are fair and reasonable to the distributors and the suppliers, while at the same time are a reasonable cost for the consumer to pay. This will frequently engage the balancing of competing interests, as well as consideration of broad public policy.

[36] Writing for the majority of the Supreme Court of Canada in *Atco, supra,* at para. 62 Bastarache J. stated that "[r]ate regulation serves several aims – sustainability, equity and efficiency – which underlie the reasoning as to how rates are fixed."

D. The Area of Expertise of its Members and the Nature of the Problem before the Board

[37] The Board was asked to consider the application of the utility to establish rates. In that context, an intervenor asked the Board to consider whether, as a factor in rate-setting, the Board could consider the interests of low-income consumers and establish a rate affordability program. That issue of rate-setting is squarely within the jurisdiction of the Board.

[38] The majority opinion in the Board Decision correctly states that the Board's mandate for economic regulation is "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate costs allocation methodologies".. However, that does not answer the question as to the full scope of the Board's jurisdiction in approving or fixing "just and reasonable rates" and adopting "any method or technique that it considers appropriate" in so doing.

[39] The Board's regulatory power is designed to act as a proxy in the public interest for competition in view of a natural gas utility's geographical natural monopoly. Absent the intervention of the Board as a regulator in rate-setting, gas utilities (for the benefit of their

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shareholders) would be in a position to extract monopolistic rents from consumers, in particular, given a relatively inelastic demand curve for their commodity. Clearly, a prime purpose of the *Act* and the Board is to balance the interests of consumers of natural gas with those of the natural gas suppliers. The Board's mandate through economic regulation is directed primarily at avoiding the potential problem of excessive prices resulting because of a monopoly distributor of an essential service.

[40] In performing this regulatory function, it is consistent for the Board to seek to protect the interests of *all* consumers vis-a-vis the reality of a monopoly. The Board must balance the respective interests of the utility and the collective interest of all consumers in rate setting. *Re Union Gas Ltd. and Ontario Energy Board et al.* (1983), 1 D.L.R. (4th) 698 (Div. Ct.), (1983) 43 O.R. (2d) 489 at 501. The Board's regulatory power is primarily a proxy for competition rather than an instrument of social policy. *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, (2006), 268 D.L.R. (4th) 408 at para. 33 [*Dalhousie*].

[41] *Dalhousie* dealt with a request for a low income affordability program like that advanced by LIEN. However, it involved a consideration of rate setting under s. 67 (1) of the Nova Scotia *Public Utilities Act* ,R.S.N.S. 1989, c. 380, which is very different in wording with respect to jurisdiction to that seen in s. 36 of the *Act* at hand. The Nova Scotia provision expressly provides that "rates shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate …." Hence, the Nova Scotia Utility and Review Board found that it did not have jurisdiction to order low income affordability programs.

[42] Section 36 of the *Act* has broad language, empowering the Board to set "just and reasonable" rates for the distribution of natural gas. The supply of natural gas can be considered a necessity that is available from a single source with prices set by the Board in the public interest. The Board has traditionally set rates on a "cost of service" basis, that is, on the basis of cost causality and employing a complex cost allocation exercise. In brief, this approach first looks to the utility's capital investments and maintenance costs including a fair rate of return to determine revenues required. The revenue requirement is then divided amongst the utility's rate paying consumers on a rate class basis (i.e., residential, commercial, industrial, etc.).

[43] The rates have been traditionally designed with the principled objective of having each rate class pay for the actual costs that class imposes upon the utility. That is, the Board has sought to avoid inter-class and intra class subsidies. See RP-2003-0063 (2005) at 5. Consistent with this approach, the Board has refused the establishment of a special rate class to provide redress for aboriginal consumers. *Decision with Reasons* EBRO493 (1997) (O.E.B.). In that case, the Ontario Native Alliance ("ONA") requested the Board to order a utility to evaluate the establishment of a rate class for the purpose of providing a special rate class for aboriginal peoples. At 316-17, the Board stated:

> The Board is required by the legislation to "fix just and reasonable rates", and in doing so it attempts to ensure that no undue discrimination occurs between rate classes, and that

> the principles of cost causality are followed in allocating the underlying rates. While the board recognizes ONA's concerns, the Board finds that the establishment of a special rate class to provide redress for aboriginal consumers of Centra does not meet the above criteria and it is not prepared to order the studies requested by ONA.

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[44] This decision would be within the Board's jurisdiction and a like response to LIEN in the case at hand would arguably be consistent and reasonable. However, the Board in dealing with the ONA request did not decline on the basis of jurisdiction. Rather, it said that it should not exercise its jurisdiction as requested by ONA for the reasons given.

[45] A low income rate affordability program would necessarily lead to treating consumer groups on a differentiated basis with higher prices for a majority of residential consumers and subsidization of the low-income subset by the majority group and/or other classes of consumers.

[46] If the Board were to reduce the rates for one class of consumers based upon an income determinant, the Board would have to increase the rates for another class or classes of consumers. In effect, such a rate reduction would impose a regressive indirect tax upon those required to pick up the shortfall. Such an approach would arguably be a dramatic departure from the Board's regulatory function as implemented to date, which has been to protect the collective interest of consumers dealing with a monopoly supplier through a "cost of service" calculation and then to treat consumers equally through determining rates to pay for the "cost of service" on a cost causality basis for classes of consumers.

[47] The Board's mandate has not been directed to the public interest in social or distributive justice through a differentiation of rates on the basis of income. That need is seen to be met through other mechanisms and programs legislated by the provincial Legislature and/or Parliament, for example, by refundable tax credits and social assistance.

[48] Indeed, the provincial income tax legislation previously provided for public tax expenditures to assist low income consumers with rising electricity costs. This was done through an "Ontario home electricity payment" by reference to income levels. *Income Tax Act*, R.S.O. 1990, c.1.2, s. 8.6.1, as rep. by *Income Tax Amendment Act (Ontario Home Electricity Relief), 2006*, S.O. 2006, c. 18, s. 1. As well, Parliament has provided a one-time relief for energy costs to low income families and seniors in Canada through the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[49] The Board is an economic regulator, rather than a formulator of social policy. While no doubt the Board must take into account broad policy considerations, rate-setting is at the core of the Board's jurisdiction. *Garland v. Consumers' Gas Company* (2000), 185 D.L.R. (4th) 536 at paras. 17, 45-46 (Ont. S.C.J.). Special rates for low income consumers would not be based upon economic principles of regulation but rather on the social principle of ability to pay. Any program to subsidize low income consumers would require a source of funding which is a matter of public policy. See generally *Re Rate Concessions to Poor Persons and Senior Citizens*, 14 Pub. Util. Rep. 4th 87 at 94 (Or. 1976).

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[50] This view of the nature and limit of the regulatory function is generally accepted as the norm in other jurisdictions. See for example *Washington Gas light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A.2d 1187 at para. 38 (D.C. Ct. App.); *State of Louisiana v. the Council of the City of New Orleans and New Orleans Public Service, Inc.* (1975), 309 So. 2nd 290 at 294 (La. Sup. Ct.).

[51] The historical common law approach for public utility regulation has been that consumers with similar cost profiles are to be treated equally so far as reasonably possible with respect to the rates paid for services. See, for example, *St. Lawrence Rendering Co. Ltd. v. The City of Cornwall,* [1951] O.R. 669-685 at 683; *Chastain et al. v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 at 454 (B.C.S.C); *Canada (Attorney General)* v. *Toronto (City)* (1893), 23 S.C.R. 514 at 519-520.

Conclusions on the Board's Jurisdiction

[52] We agree that the traditional approach of "cost of service" is the root principle underlying the determination of rates by the Board because that is necessary to meet the fundamental, core objective of balancing the interests of all consumers and the natural monopoly utility in rate/price setting.

[53] However, the Board is authorized to employ "any method or technique that it considers appropriate" to fix "just and reasonable rates." Although "cost of service" is necessarily an underlying fundamental factor and starting point to determining rates, the Board must determine what are "just and reasonable rates" within the context of the objectives set forth in s. 2 of the *Act*. Objective #2 therein speaks to protecting "the interests of consumers with respect to prices."

[54] The "cost of service" determination will establish a benchmark global amount of revenues resulting from an estimated quantity of units of natural gas or electricity distributed. The Board could use this determination to fix rates on a cost causality basis. This has been the traditional approach.

[55] However, in our view, the Board need not stop there. Rather, the Board in the consideration of its statutory objectives might consider it appropriate to use a specific "method or technique" in the implementation of its basic "cost of service" calculation to arrive at a final fixing of rates that are considered "just and reasonable rates." This could mean, for example, to further the objective of "energy conservation", the use of incentive rates or differential pricing dependent upon the quantity of energy consumed. As well, to further the objective of protecting "the interests of consumers" this could mean taking into account income levels in pricing to achieve the delivery of affordable energy to low income consumers on the basis that this meets the objective of protecting "the interests of consumers with respect to prices."

[56] The Board is engaged in rate-setting within the context of the interpretation of its statute in a fair, large and liberal manner. It is not engaged in setting social policy.

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[57] This is not, of course, to imply any preferred course of action in rate setting by the Board. The Board in its discretion may determine that "just and reasonable rates" are those that follow from the approach of "cost causality" once the "cost of service" amount is determined. That is, the principle of equality of rates for consumers within a given class (e.g., residential consumers) may be viewed as the most just and reasonable approach. A determination by the Board that all residential gas consumers (with relatively minor deviations through such programs as the "Winter Warmth Program") pay the same distribution rates is not in itself discriminatory on a prohibited ground. Indeed, it can be seen as a non-discriminatory policy in terms of prices paid.

[58] Nor is it to suggest that as a matter of public policy, objectives of distributive justice or conservation in respect of energy consumption are best achieved by rate setting as compared to, for instance, tax expenditures or social assistance devised and implemented by the Legislature through mechanisms independent of the operation of the *Act*. It is noted that the Minister is given the authority in s. 27 of the *Act* to issue policy statements as to matters that the Board must pursue; however, the Minister has not issued any policy statement directing the board to base rates on considerations of the ability to pay. Moreover, the power granted to a regulatory authority "must be exercised reasonably and according to the law, and cannot be exercised for a collateral object or an extraneous and irrelevant purpose, however commendable." *Re Multi Malls Inc. et al. and Minister of Transportation and Communications et al* (1977), 14 O.R. (2d) 49 at 55 (C.A.). As we have said, cost of service is the starting point building block in rate setting, to meet the fundamental concern of balancing the interests of all consumers with the interests of the natural monopoly utility.

[59] Nor does our conclusion presume as to what methods or techniques may be available in determining "just and reasonable rates." Efficiency and equity considerations must be made. Rather, this is to say only that so long as the global amount of return to the utility based upon a "cost of service" analysis is achievable, then the rates/prices (and the methods and techniques to determine those rates/prices) to generate that global amount is a matter for the Board's discretion in its ultimate goal and responsibility of approving and fixing "just and reasonable rates."

[60] The issue before the Court is that of jurisdiction, not how and the manner by which the Board should exercise the jurisdiction conferred upon it.

[61] In our view, and we so find, the Board has the jurisdiction to take into account the ability to pay in setting rates. We so find having taken into account the expansive wording of s. 36 (2) and (3) of the statute and giving that wording its ordinary meaning, having considered the purpose of the legislation within the context of the statutory objectives for the Board seen in s. 2, and being mindful of the history of rate setting to date in giving efficacy to the promotion of the legislative purpose.

[62] We also find that that interpretation is appropriate taking into account the criteria articulated in *Driedger*, above, namely it complies with the legislative text, it promotes the legislative purpose and the outcome is reasonable and just.

[63] As indicated above, a statutory administrative tribunal obtains its jurisdiction from explicit powers or implicit powers. Having found that the jurisdiction to consider ability to pay in rate setting is explicitly within the *Act*, we need not consider the doctrine of necessary implication or the related principle of implied exclusion.

The issue of the *Canadian Charter of Rights and Freedoms*

[64] Before concluding, it is appropriate to mention the submission made on behalf of LIEN in respect of s. 15 (1) of the *Canadian Charter of Rights and Freedoms*, Part 1 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act, 1982* (U.K.), c. 11 (the "*Charter*").

[65] LIEN says it raises the *Charter* simply within the context of it being an interpretive tool in discerning the meaning of an asserted ambiguous s. 36 of the *Act*. LIEN says it does not raise any issue that the *Act* or the Board's actions or inactions are contrary to the *Charter*.

[66] LIEN argues that in the absence of clear statutory provisions, the requirement for "just and reasonable rates" must be interpreted to comply with s. 15. The *Charter* applies to provincial legislation and can be used as an interpretive tool. *R. v. Rogers*, [2006] 1 S.C.R. 554, [2006] S.C.J. No. 15 at para. 18. In our view, as stated above, the *Act* provides the Board with the requisite jurisdiction without having to look to the *Charter*.

[67] While we heard submissions from LIEN, we declined to hear from counsel for the respondents on this issue. We agree with our colleague Swinton J. that such an argument requires a full evidentiary record.

Disposition

[68] For the reasons given, the appeal is allowed and it is declared that the Board has the jurisdiction to establish a rate affordability assistance program for low income consumers purchasing the distribution of natural gas from the utility, EGD.

[69] All parties agree that there is not to be any award of costs in respect of this appeal.

____

KITELEY J.

____

CUMMING J.

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Swinton J. (dissenting):

[70] The sole issue in this appeal is whether the Ontario Energy Board (the "Board") erred in holding that it had no jurisdiction, when setting residential rates for gas distribution, to order a rate affordability program for low income consumers. In my view, the majority of the Board was correct in concluding that the Board lacked jurisdiction to make such an order.

[71] The majority of the Board predicated its decision on the understanding that the appellants' proposal contemplated the establishment of a rate group for low income residential consumers that would be funded by general rates. I, too, proceed on that assumption. While there were no details of a specific program put forth by the appellants during the hearing, it is inevitable that the Board, in setting lower rates for the economically disadvantaged, would have to impose higher rates on other consumers.

The Board's Practice in Setting Rates

[72] Pursuant to the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B (the "Act"), the Board has authority to set rates for both gas and electricity. It has traditionally set rates for gas through a "cost of service" assessment, in which it seeks to determine a utility's total cost of providing service to its customers over a one year period (the "test year"). According to the Board's factum, these costs include the rate base (which is essentially the net book value of the utility's total capital investments) and the utility's operational and maintenance costs for the test year, among other things. The utility's total costs for the test year (usually including a rate of return on the rate base portion) forms the revenue requirement. The revenue requirement is then divided amongst the utility's ratepayers on a rate class basis (that is, residential, small commercial, industrial, etc.).

[73] With respect to gas, it has always been the Board's practice to allocate the revenue requirement to the different rate classes on the basis of how much of that cost the rate class actually causes ("cost causality"). To the greatest extent possible, the Board has striven to avoid inter-class subsidies (see, for example, Decision with Reasons, RP-2003-0063 (2005), p. 5).

The Proper Approach to Statutory Interpretation

[74] To determine the issue in this appeal, it is necessary to consider the powers conferred on the Board by its constituent legislation, the *Ontario Energy Board Act*. That Act must be interpreted using the modern principles of statutory interpretation described by Professor Ruth Sullivan in *Driedger on the Construction of Statutes* (3rd ed.) (Toronto: Butterworths, 1994) as follows:

> There is only one rule in modern interpretation, namely, courts are obliged to determine the meaning of legislation in its total context, having regard to the purpose of the

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> legislation, the consequences of proposed interpretations, the presumptions of special rules of interpretation, as well as admissible external aids. In other words, the courts must consider and take into account all relevant and admissible indicators of legislative meaning. After taking these into account, the court must then adopt an interpretation that is appropriate. An appropriate interpretation is one that can be justified in terms of (a) its plausibility, that is, its compliance with the legislative text; (b) its efficacy, that is, its promotion of the legislative purpose; and (c) its acceptability, that is, the outcome is reasonable and just. (at p. 131)

[75] The words of a statute are to be read in their entire context and in their grammatical and ordinary sense, harmoniously with the scheme of the Act, its objects, and the intent of the Legislature (*ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, [2006] 1 S.C.R. 140 at para. 37).

The Words of the Provision in Issue

[76] Subsection 36(2) of the Act gives the Board the broad authority to approve or fix "just and reasonable" rates for the distribution of gas. On its face, those words might encompass the power to set rates according to income. However, the words do not explicitly confer the power to do so, and the Supreme Court of Canada commented in *ATCO, supra* that a discretionary grant of authority to a tribunal cannot be viewed as conferring unlimited discretion. A regulatory tribunal must interpret its powers "within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature is assumed to have had regard in passing that legislation" (at para. 50).

[77] The appellants also rely on s. 36(3), which states that in approving or fixing just and reasonable rates, the Board may adopt "any method or technique that it considers appropriate". These words were added to the Act in 1998. Examples of methods or techniques used by the Board for setting gas distribution rates are cost of service regulation and incentive regulation.

[78] On its face, the words of s. 36(3) do not confer the jurisdiction to provide special rates for low income customers. The subsection replaced an earlier provision of the Act which required a traditional cost of service analysis in setting rates. I agree with the conclusion of the Board majority as to the meaning of s. 36(3) (Reasons, p. 10):

> It gives the Board the flexibility to employ other methods of ratemaking in fixing just and reasonable rates, such as incentive ratemaking, rather than the traditional costs of service regulation specified in section 19 of the old Act. The change in the legislation was coincident with the addition of the regulation of the electricity sector to the Board's mandate. The granting of the authority to use methods other than cost of service to set rates for the gas sector was an alignment with the non-prescriptive authority to set rates for the electricity sector. The Board is of the view that if the intent of the legislature by the new language was to include ratemaking considering income level as a rate class determinant, the new Act would have made this provision explicit given the opportunity

at the time of the update of the Act and the resultant departure from the Board's past practice.

The Regulatory Context

[79] According to longstanding principles governing public utilities developed under the common law, a public utility like the respondent Enbridge Gas Distribution Inc. ("Enbridge") must treat all its customers equally with respect to the rates they pay for a particular service (*Attorney General of Canada v. The Corporation of the City of Toronto* (1892), 23 S.C.R. 514 at 519-20; St. *Lawrence Rendering Co. Ltd. v. Cornwall*, [1951] O.R. 669 (H.C.J.) at 683; *Chastain v. British Columbia Hydro and Power Authority* (1972), 32 D.L.R. (3d) 443 (B.C.S.C.) at 454).

[80] As noted in the Board's majority reasons, the Board is, at its core, an economic regulator (Reasons, p. 4). Rate setting is at the core of its jurisdiction (*Garland v. Consumer's Gas Company* (2000), 185 D.L.R. (4th) 536 (Ont. S.C.J.) at para. 45). I agree with the majority's description of economic regulation as being "rooted in the achievement of economic efficiencies, the establishment of fair returns for natural monopolies and the development of appropriate cost allocation methodologies" (Reasons, p. 4).

[81] Historically, in setting rates, the Board has engaged in a balancing of the interests of the regulated utility and consumers. The Board has not historically balanced the interests of different groups of consumers. As the Divisional Court stated in *Union Gas Ltd. v. Ontario (Energy Board)* (1983), 43 O.R. (2d) 489 at p. 11 (Quicklaw):

> … it is the function of the O.E.B. to balance the interest of the appellant in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interest of its customers to be served as cheaply as possible.

See, as well, *Northwestern Utilities v. The City of Edmonton*, [1929] 1 S.C.R. 186 at 192.

[82] In a similar vein, the Supreme Court in *ATCO, supra* spoke of a "regulatory compact" which ensures that all customers have access to a utility at a fair price. The Court went on to state (at para. 63):

> Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specified area at rates that will provide companies the opportunity to earn a fair rate of return for all their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers of their defined territories, and are required to have their rates and certain operations regulated…

The Court described the object of the Act "to protect both the customer *and* the investor" (at para. 64).

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[83] The Legislature, in conferring power on the Board, must be taken to have had regard to the principles generally applicable to rate regulation (*ATCO, supra* at paras. 50 and 64). I agree with the submission of Enbridge that those principles are the following:

> (a) customers of a public utility must be treated equally insofar as the rate for a particular service or class of services is concerned; and
>
> (b) the Legislature will be presumed not to have intended to authorize discrimination among customers of a public utility unless it has used specific words to express this intention.

[84] Thus, the considerations of justice and reasonableness in the setting of rates have been and are those between the utility and consumers as a group, not among different groups of consumers based on their ability to pay.

Other Provisions of the Act

[85] In applying s. 36(2), the Board must be bound by the objectives set out in s. 2 of the Act, which includes

> 2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

[86] The appellants submit that these words are broad enough to permit the Board to order a rate affordability assistance program. However, that is not obvious from the words used, which refer to "consumers" as a whole, and not to any particular subset of consumers. Indeed, it can be argued that any low income rate affordability program would run counter to the stated objective, given that such a program must almost certainly be funded through higher rates paid by other consumers. The result would be to provide benefits to one group of consumers at the expense of others.

[87] The reason for this conclusion lies in the Board's historical approach to rate setting, as described earlier in these reasons. The Board sets a revenue requirement for utilities before allocating those costs to the different rate classes. The only way the utility could recover its revenue requirement, given a rate class with lower rates for low income consumers, would be to increase the rates charged to other classes. Therefore, such higher prices can not be seen as protecting the interests of consumers with respect to prices, as set out in objective 2.

[88] Moreover, the Act contains an explicit provision in s. 79 that allows the Board to provide rate protection for rural and remote customers of electricity distributors. Subsection 79(1) provides:

> The Board, in approving just and reasonable rates for a distributor who delivers electricity to rural or remote consumers, shall provide rate protection for those consumers

> or prescribed classes of those consumers by reducing the rates that would otherwise apply in accordance with the prescribed rules.

Section 79 also provides grandfathering for those who had a subsidy prior to the change in the Act. As well, it explicitly allows the distributor to be compensated for the subsidized rates through contributions from other consumers, as provided by the regulations.

[89] This section was added to the Act in 1998, when the Board was given the authority over electricity rate regulation. Section 79 ensured the ongoing protection of rural rates put in place when electricity distribution was regulated by Ontario Hydro.

[90] One of the principles of statutory interpretation is "implied exclusion". As Professor Sullivan has stated, this principle operates "whenever there is reason to believe that if the legislature had meant to include a particular thing within its legislation, it would have referred to that thing expressly" (*supra*, p. 186). While the purpose of s. 79 of the Act was to protect a pre-existing policy to assist rural and remote residential consumers, nevertheless, it is telling that there is no similar explicit power to order special rates or rate subsidies for other groups elsewhere in the Act.

The Significance of Ordering Rate Affordability Programs

[91] An appropriate interpretation can be justified in terms of its promotion of the legislative purpose and the reasonableness of the outcome (see Sullivan, quoted above at para. 5).

[92] The ability to order a rate affordability program would significantly change the role that the Board has played – indeed, the majority of the Board stated a number of times that the proposal to base rates on income level would be a "fundamental" departure from its current practice. In the past, the Board has acted as an economic regulator, balancing the interests of the utility and its shareholders against the interests of consumers as a group. Were it to assume jurisdiction over rate affordability programs, it would carry out an entirely different function. It would enter into the realm of social policy, weighing the interests of low income consumers against those of other consumers. This is not a role that the Board has traditionally played. This is not where its expertise lies, nor is it well-suited to taking on such a role.

[93] An examination of the particular case before the Board illustrates this. The appellants seek a rate affordability assistance program for gas in response to Enbridge's application for a rate increase for gas distribution – that is, for the *delivery* of natural gas. Customers can make arrangements for the purchase of the commodity of natural gas with a variety of suppliers in the competitive market. Therefore, were the Board to assume jurisdiction to order a rate affordability assistance program here, it could address only one part of the problem that low income consumers face in meeting their heating costs – the cost of distribution of gas.

[94] In addition, the Board would have to consider eligibility criteria for a rate affordability assistance program that reasonably would take into account existing programs for assistance to

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low income consumers. Obviously, this would include social assistance programs. As well, Enbridge, in its factum, has identified other programs which provide assistance for low income consumers. For example, the Ontario government has implemented a program to assist low income customers with rising electricity costs through amendments to income tax legislation (*Income Tax Act*, R.S.O. 1990, c. I.2, s. 8.6.1, as amended S.O. 2006, c.18, c.1). At the federal level, there was one-time relief for low income families and senior citizens provided by the *Energy Costs Assistance Measures Act*, S.C. 2005, c. 49.

[95] Moreover, in order to cover the lower costs, the Board would have to increase the rates of other customers in a manner that would inevitably be regressive in nature, as it is difficult to conceive how the Board would be able to determine, in a systematic way, the ability of these other customers to pay.

[96] Clearly, the determination of the need for a subsidy for low income consumers is better made by the Legislature. That body has the ability to consider the full range of existing programs, as well as a wide range of funding options, while the Board is necessarily limited to allocating the cost to other consumers. The relative advantages of a legislative body in establishing social programs of the kind proposed are well described in the following excerpt from a decision of the Oregon Public Utility Commissioner (*Re Rate Concessions to Poor Persons and Senior Citizens* (1976), 14 PUR 4th 87 at p. 94):

> Utility bills are not poor persons' only problems. They also cannot afford adequate shelter, transportation, clothing or food. The legislative assembly is the only agency which can provide comprehensive assistance, and can fund such assistance from the general tax funds. It has the information and responsibility to deal with such matters, and can do so from an overall perspective. It can determine the needs of various groups and compare those needs to existing social programs. If it determines a special program is needed to deal with energy costs, it can affect all energy sources rather than only those the commissioner regulates.
>
> With clear authority to establish social welfare policy, the legislative assembly also can monitor all state and federal welfare programs and the sources and extent of aid given to different groups. Without such overview, as independent agencies aid various segments of society, the total aid given each group is unknown, and unequal treatment of different groups becomes likely.

[97] Where the issue of rate affordability programs has arisen in other jurisdictions, courts and boards have ruled that a public utilities board does not have jurisdiction to set rates based on ability to pay (see, for example, *Washington Gas Light Co. v. Public Service Commission of the District of Columbia* (1982), 450 A. 2d 1187 (D.C. Ct. App.) at para. 38; *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.* (2006), 268 D.L.R. (4th) 408 (N.S.C.A.) at 419; Alberta Energy and Utilities Board Decision 2004-066, Section 9.2.6 at 161, as well as the Oregon case, *supra*).

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[98] The appellants distinguish the *Dalhousie Legal Aid* case because the Nova Scotia legislation is different from Ontario's. Specifically, s. 67(1) of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 provides that "[a]ll tolls, rates and charges shall always, under substantially similar circumstances and conditions in respect of service of the same description, be charged equally to all persons and at the same rate".

[99] While the language of the two statutes does differ, nevertheless, the reasons of the Nova Scotia Court of Appeal make it clear that the Board's role is not to set social policy. At para. 33, Fichaud J.A, observed, "The Board's regulatory power is a proxy for competition, not an instrument of social policy."

[100] Moreover, the principle in s. 67(1) of the Nova Scotia Act requiring that rates be charged equally is a codification of the common law, set out earlier in these reasons. The Ontario Board has long operated according to the same principles.

[101] The appellants submit that the recent decision in *Allstream Corp. v. Bell Canada*, [2005] F.C.J. No. 1237 (C.A.) assists their case. There, the Federal Court of Appeal upheld a decision of the Canadian Radio-Television and Telecommunications Commission (the "CRTC") approving special facilities tariffs submitted by Bell for the provision of optical fibre services pursuant to certain customer-specific arrangements. All but one related to a Quebec government initiative aimed at supporting the construction of broadband networks for rural municipalities, school boards and other institutions. The Court determined that the Commission's decision approving the tariffs was not patently unreasonable, given the exceptional circumstances of the case that justified a deviation from the normal practice of rate determination. The Court noted that the Commission considered matters that were not purely economic, but noted that such considerations were part of the Commission's wide mandate under s. 7 of the *Telecommunications Act,* S.C. 1993, c. 38 (at paras. 34-35).

[102] Section 7 of that Act, unlike s. 2 of the *Ontario Energy Board Act*, expressly includes the power "to respond to the economic and social requirements of users of telecommunications services" (s. 7(h)), as well as to enrich and strengthen the social and economic fabric of Canada and its regions (s. 7(a)). Moreover, while s. 27(2)(b) of that Act forbids unjust discrimination in rates charged, s. 27(6) explicitly permits reduced rates, with the approval of the Commission, for any charitable organization or disadvantaged person.

[103] In contrast to the broad mandate given to the CRTC, the objectives of the Board are much more confined. When the Board's objectives go beyond the economic realm, specific reference has been made to other objectives, such as conservation and consumer education (s. 2 (5) and (6)). There is no reference to the consideration of economic and social requirements of consumers.

[104] The appellants have also pointed out that the Board has in the past authorized programs that transfer benefits to lower income customers. The Winter Warmth program is one in which individuals can apply for emergency financial relief with heating bills. It is triggered by an

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application from a particular customer, and the program is funded by all customers. The fact that the Board has approved this charitable program does not lead to the conclusion that it has jurisdiction to set rates on the basis of income level.

[105] With respect to the Demand Side Management (DSM) programs, the majority of the Board explained that this is not equivalent to a rate class based on income level. At p. 11 of its Reasons, the majority stated,

> The Board is vigilant in ensuring that customer groups are afforded the opportunity to receive the benefits of the costs charged. In the case of Demand Side Management (DSM) programs, for example, the Board has ordered that specific funding be channeled for programs aimed at low income customers. It cannot be argued that this constitutes discriminatory pricing. Rather, the contrary. It is an attempt to avoid discrimination against low income customers who also pay for DSM programs but may not have equal opportunities to take advantage of these programs.

[106] Were the Board to assume jurisdiction to order a rate affordability assistance program, it would be taking on a significant new role as a regulator of social policy. Given the dramatic change in the role that it has historically played, as well as the departure from common law principles, it would require express language from the Legislature to confer such jurisdiction

Jurisdiction by Necessary Implication

[107] In order to impute jurisdiction to a regulatory body, there must be evidence that the exercise of the power in question is a practical necessity for the regulatory body to accomplish the goals prescribed by the Legislature (*ATCO*, *supra* at paras. 51, 77). In this case, there is no evidence that the power to implement a rate affordability assistance program is a practical necessity for the Board to meet its objectives as set out in s. 2.

The Role of the Charter

[108] The appellants submit that the values found in s. 15 of the *Canadian Charter of Rights and Freedoms* should be considered in the interpretation of the ratemaking provisions of the Act. However, the Charter has no relevance in interpretation unless there is genuine ambiguity in the statutory provision (*R. v. Rodgers*, [2006] 1 S.C.R. 554 at paras. 18-19). A genuine ambiguity is one in which there are "two or more plausible readings, each equally in accordance with the intentions of the statute" (at para. 18).

[109] In my view, there is no ambiguity in the interpretation of s. 36 of the Act, and therefore, there is no need to resort to the Charter.

[110] In any event, the appellants' argument is, in fact, that the failure of the Board to order a rate affordability program is discriminatory on the basis of sex, race, age, disability and social assistance, because of the adverse impact on these groups (Factum, para. 43, as well as para. 47).

Such an argument can not be made without a full evidentiary record, and the inclusion of statistical material in the Appeal Book is not a sufficient basis on which to address this equality argument.

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Conclusion

[111] For these reasons, I am of the view that the majority decision of the Board was correct, and that the Board has no jurisdiction to order rate affordability assistance programs for low income consumers. Therefore, I would dismiss the appeal.

Swinton J.

Released: May 16, 2008

COURT FILE NO.: 273/07
DATE: 20080516

2008 CanLII 23487 (ON SCDC)

ONTARIO
SUPERIOR COURT OF JUSTICE

DIVISIONAL COURT

KITELEY, CUMMING AND SWINTON JJ.

B E T W E E N:

ADVOCACY CENTRE FOR TENANTS-ONTARIO and INCOME SECURITY ADVOCACY CENTRE on behalf of LOW-INCOME ENERGY NETWORK

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

REASONS FOR JUDGMENT

Released: May 16, 2008

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ENERGY REGULATION IN ONTARIO

Glenn Zacher • Patrick G. Duffy

(formerly authored by David M. Brown)

Release No. 7, July 2011

What's New in this Update:

- This update of *Energy Regulation in Ontario* contains substantial revisions to Chapters 6 and 14 that were necessary as a result of the new *Energy Consumer Protection Act, 2010*, S.O. 2010, c. 8 (in force January 1, 2011).

Case Law Highlights

- *Summitt Energy Management*, EB-2010-0221, in which the Ontario Energy Board issued an administrative penalty and costs totalling up to $299,000 against an energy marketer related to sales agent activities that contravened the *Ontario Energy Board Act, 1998*.

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Legislation Highlights

- This update deals in detail with the *Energy Consumer Protection Act, 2010*, S.O. 2010, c. 8, and related amendments, regulations and codes.

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the application to such owners as prescribed by the statute. It is only when that determination is made that what theretofore was a general location becomes a specific or final location of the line.

With respect to applications involving hydrocarbon transmission lines, if in its opinion special circumstances of a particular case so require, the Board may, without a hearing, exempt any person from the requirement of obtaining a Board order.[192] The Board has granted exemptions where there is an immediate need for the project, an environmental review has ben completed and there is no opposition from affected landowners.[192a]

On a leave-to-construct application, the applicant must demonstrate that the proposed work is "in the public interest".[193] In assessing the public interest, the Board will consider the need, safety, economic feasibility, community benefits, security of supply and environmental impact of the proposed pipeline. A critical component of any pipeline application is evidence that the construction of the pipeline is economically feasible,[194] and the construction costs of the pipeline are an important factor in assessing the economic feasibility of the line.[195] When considering the public interest, the Board is limited to considering the effects of the actual pipeline construction, as opposed to the end use effects of the gas being supplied by that pipeline.[196]

If, after considering a pipeline or facilities application, the Board is of the opinion that the construction, expansion or reinforcement of the proposed work is in the public interest, it will make an order granting leave to carry out the work.[197] Leave to construct cannot be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board.[198] A landowner is always free to refuse to sign an easement agreement proposed by an applicant. In such a case, if the pipeline is to cross the landowner's lands, the applicant must then apply to the Board for authority to expropriate the necessary easement rights, subject to payment of compensation to the landowner.

Where the Board considers that the provisions of its standard-form easement agreement may not adequately deal with factors raised by any particular pipeline application, the Board may include special conditions in its order. For example, where the size of the pipeline may result in unusual soil displacement or problems with tile draining systems, the Board can impose

192 *OEB Act*, s. 95.
192a Ontario Energy Board, Decision and Order, EB-2010-0154 (May 13, 2010).
193 *Ibid.*, s. 96.
194 Ontario Energy Board, Decision in *Union Gas Limited*, E.B.L.O. 167 (March 15, 1974).
195 Ontario Energy Board, Decision in *Union Gas Limited*, E.B.L.O. 167-I (February 12, 1975). The components of the economic feasibility test employed by the OEB are discussed in section 4:120:20.3, *infra*.
196 *PWU v. Ontario Energy Board* (2006), 214 O.A.C. 208 (S.C.J. (Div. Ct.)). See also Ontario Energy Board, Decision and Order in EB-2006-0305 (June 1, 2007).
197 *OEB Act*, s. 96.
198 *Ibid.*, s. 97.

E.B.L.O. 231
E.B.C. 193, 194
E.B.A. 591, 592

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1980, c. 332, Sections 46 and 48, as amended;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. to the Ontario Energy Board for an Order granting leave to construct a natural gas transmission pipeline in the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, in the County of Renfrew;

AND IN THE MATTER OF the Municipal Franchises Act, R.S.O. 1980, c. 309, Sections 8 and 9;

AND IN THE MATTER OF Applications by The Consumers' Gas Company Ltd. for certificates of public convenience and necessity to construct works to supply gas and to supply gas to inhabitants of the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, in the County of Renfrew;

AND IN THE MATTER OF the approval of proposed municipal franchise by-laws granting The Consumers' Gas Company Ltd. the right to construct works to supply and to supply gas to the inhabitants of the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, in the County of Renfrew.

BEFORE: R.R. Perdue, Q.C.
Presiding Member

C.W.W. Darling
Member

FINAL DECISION WITH REASONS

June 28, 1991

1. INTRODUCTION

1.0.1 By way of a letter to the Ontario Energy Board, ("the Board"), dated May 6, 1991, The Consumers' Gas Company Ltd, ("Consumers Gas" or "the Company"), requested the Board to reconvene the hearing on its application to provide natural gas to the Town of Deep River and the Township of Rolph, Buchanan, Wylie and McKay, (collectively known as "the Town" or "Deep River").

1.0.2 The substance of the Company's application is fully set out in the Board's Interim Decision on this matter dated June 18, 1990, which was amended by a further Interim Decision dated January 23, 1991. For purposes of this hearing, the application can be summarized as follows: Consumers Gas seeks leave to construct certain facilities costing about $1.1 million to serve the residents of both municipalities and, as well, it is seeking the necessary franchises and Certificates of Public Convenience and Necessity.

1.0.3 The delays and the interim nature of the Board's two previous decisions in this matter were intended to allow the Company and the Town enough time to find an appropriate means of financing a contribution-in-aid of construction of $400,000 which the Board found to be necessary in order for the project to proceed. The final deadline set by the Board was June 30, 1991 at which time, if the means of financing had not been found, the Board indicated that it would re-open the hearing itself and deny the Company's application as not being economically feasible.

1.0.4 The Company's letter requesting the hearing to be re-opened indicated that:

- Its construction costs were now reduced by $72,905 which thereby reduces the contribution required; and
- A finance plan had been developed whereby the Company intends to lend the new customers $360,590.

1.0.5 As a result of this information, the Board ordered the hearing to be re-opened and on May 28, 1991 the two remaining Board members on the original Panel heard the Company's evidence together with argument. R.M.R. Higgin, who presided over the two previous hearings on this matter, left the Board upon completion of his appointment on March 31, 1991.

1.0.6 A verbatim transcript of all the hearings together with the exhibits are available for examination at the Board's offices.

1.1 THE APPLICATION

1.1.1 The Company's pre-filed evidence for this hearing indicated that the loan proposed by the Company would result in a residential hot water heating customer paying an extra $3.49 per month in addition to charges for gas usage, while a residential customer contracting for heating service would pay an extra $11.23 per month and a customer taking both space and hot water heating would pay an extra $14.72 per month.

1.1.2 The loan would carry an interest rate on the outstanding balance of 1.25 percent per month which is an annual effective rate of 16.075 percent. Based on the Company's forecast of customer attachments, the loan plus interest would be repaid over a ten year period.

1.1.3 Commercial customers would repay the loan based on a formula utilizing the forecast of the customer's annual volume which, under exceptional circumstances, would be subject to adjustment.

1.1.4 The company testified that the precise term of the loan would vary according to the actual customer attachments.

1.1.5 In order to determine what effect this loan and its repayment schedule would have upon the Company's customer attachment schedule, Consumers Gas conducted a telephone survey in early January 1991, of 109 residents who had initially indicated their desire to convert to gas. Of those contacted, 90 were still interested and 19 were not. They also contacted 122 residents who, according to an earlier survey, were not interested in converting to gas. Twenty-two of these residents were now interested in converting while the remaining 100 were not.

1.1.6 As well, the Company discussed the loan repayment schedule with approximately 30 residential customers and received a signed agreement by 24 of those residents accepting the conditions as outlined above.

1.1.7 The Company also reviewed the proposed loan arrangements with eight potential commercial customers and obtained signed loan agreements from all eight. The loan repayment charge for these customers ranged from approximately $20 per month to more than $400 per month.

1.1.8 Mayor Smith of Deep River appeared as a witness at the hearing and as a result of a resolution of Council supporting the agreement, voiced his approval for the plan. In the original hearing (before taking the loan agreement into account), Consumers Gas calculated that a typical residential customer converting to gas would save 40 percent of a $1,300 annual oil bill; 48 percent of a $1,500 annual electricity bill and 62 percent of a $2,100 annual propane bill.

1.1.9 The Company witnesses testified that Consumers Gas and the Town were still seeking a contribution-in-aid of construction from Ontario Hydro which, if forthcoming, would offset part of the loan. Ontario Hydro was being canvassed for a contribution because gas service to Deep River would remove some of Hydro's heat sensitive load thereby assisting the electrical utility to better manage its demand.

1.1.10 The Company's evidence indicated that it intended to follow the Board approved practice of including in rate base the cost of the project minus the contribution-in-aid of construction. However, as a second asset, the Company proposed to include in rate base the amount of the loan itself which would be reduced over time by the customer repayments pursuant to the amortization schedule. The proposed interest income from the loan would be included in the utility's overall income and the Company witnesses testified that it was sufficient to fully carry the principal of the loan at the current before tax allowed rate of return.

1.1.11 Board Staff argued that none of the loan should be included in rate base. It argued that if the Company's attachment forecast is incorrect, the interest and repayment schedule proposed by the Company will not be sufficient to meet the return on the increase in rate base due to the inclusion of the loan amount and the resulting shortfall will be paid for by all customers of Consumers Gas, not just those in Deep River. It also argued that the customer forecast together with a schedule showing the actual and forecast attachments and repayments should be examined annually.

1.1.12 In addition, Board Staff submitted that the Company's legal and hearing costs were understated by about $56,667 which, if correct, would tend to lower the amount to be paid by the residents of Deep River and increase the subsidy to be paid by the Company's current customers.

1.1.13 The Company's evidence was that its original forecast for legal and hearing costs was $47,670 but that these items had actually cost $61,667 with a further $5,000 still to come for this final hearing. However, for purposes of determining the contribution-in-aid of construction, the Company's evidence was that the legal and hearing costs would not be increased but that the excess over the original forecast ($18,997) would be attributed to the generic nature of the hearing and charged to all the Company's customers.

1.1.14 Board Staff took exception to this procedure and argued that the Company be directed to undertake another DCF analysis which, they submitted, would show that the necessary contribution-in-aid of construction would exceed $400,000 and in such an event, the Board should cap the contribution at that amount.

1.1.15 Board Staff also argued that for this latest hearing, the Company inappropriately removed from its feasibility calculations an additional $35,000 in costs. The Company argued that the $35,000 in question was incurred in 1986 for E.B.L.O. 216 and therefore not directly attributable to the current Deep River application and should be removed in spite of its being included in the June, 1990 application.

Board Findings

1.1.16 It is the opinion of the Board that, for the following reasons, the general thrust of the proposal as structured by Consumers Gas meets the basic overall objectives laid out in the Board's Interim Decision dated June 18, 1990:

- The amount of the contribution-in-aid of construction appears to fairly allocate the costs and benefits of the project between the utility's future and current customers; and

- The broad public interest factors of extending gas service to Deep River are met in a fashion consistent with the reasoning outlined in that decision.

1.1.17 However, the Board is concerned that at this stage in the hearing, (after two interim decisions and more than a year after the evidence in the first part of this hearing was completed), the Company chose to remove from its calculations the following two sets of costs:

- $18,997 being the excess amount over the original forecast of legal and hearing costs for this hearing which the Company termed generic and therefore not attributable to this hearing; and

- $35,000 associated with the costs of E.B.L.O. 216.

1.1.18 Without commenting on the merits of including or not including such costs in the feasibility analysis or the contribution-in-aid of construction, the Board is of the opinion that their removal at this stage was inappropriate in spite of the small amounts involved.

1.1.19 However, because of the de-minimis effect on the proposed monthly payments and because of the potential for confusion among customers if the amounts were to be included, the Board will not direct Consumers Gas to re-run its DCF analysis to re-incorporate these amounts or to increase the contribution-in-aid of construction.

1.1.20 However, the Board points out that, although the belated but simple gesture of re-allocating some of these costs as generic removed them from consideration in this case, they are still subject to the normal prudency test that all expenditures undergo in a rates case and if the Board in that hearing finds that they are not generic, they may not be recovered at all.

1.1.21 The Board hereby directs the Company at its next rates case to provide direct evidence on this particular issue as well as the Board's second concern outlined above dealing with the removal of costs associated with E.B.L.O. 216.

1.1.22 The Board approves the Company's proposed arrangement for the contribution-in-aid of construction and finds that the application, E.B.L.O. 231, to construct the NPS 4 transmission pipeline and its related facilities to supply the Town of Deep River and the Township of Rolf, Buchanan, Wylie and McKay is economically feasible. The Board has examined the environmental report and the route as proposed and as both indicate no concerns, the Board grants the Company leave to construct the facilities as requested.

1.1.23 As well, because the proposed arrangement is within the public interest and meets all the requirements in that regard, the Board approves the term and all the conditions outlined in the applications for Certificates of Public Convenience and Necessity to construct works and supply gas to Deep River and the said Township, (E.B.C. 193 and 194).

1.1.24 The Board also approves the applications, (E.B.A. 591 and 592), for orders approving the gas franchise agreements outlined in by-laws passed by Deep River and the Township and directs that the vote of the electors in both cases is not necessary.

1.1.25 By granting these applications, the Board has manifested its approval of the customer re-payment arrangement as presented by the Company and approved by the Town Council. However, the Board points out that barring any external contribution and in the event that fewer customers than expected contract for service, part of the loan could still be outstanding at the end of the ten year period. If this occurs, the Company has indicated that it would extend the term until the debt is repaid which produces an unknown liability for the gas customers in Deep River.

1.1.26 This risk of non-payment at the end of the term is also a key issue for the Company's current customers and its shareholders. In fact, part of the Company's proposal was to include the loan in rate base. By following this proposal, the risk of loss is primarily borne by the utility's customers whereas, by disallowing the loan in rate base, the risk is primarily assumed by the Company's shareholders.

1.1.27 Because this apportionment of the loan is not a matter for this panel of the Board and will more than likely become a contentious issue in the Company's next rate case, it will not accept the implied invitation of either party to these proceedings to comment further on the proposal.

2. COSTS AND COMPLETIONS OF THE PROCEEDINGS

2.0.1 No party requested costs for this portion of the hearing and therefore no order will made in that regard. Insofar as the Board's costs are concerned, they shall be paid by the Company upon receipt of the Board's Cost Order and invoices in that regard.

2.0.2 The conditions of approval attached to and forming part of this Decision with Reasons shall form part of the Order giving effect to the Board's Decisions in this regard and the approval granted thereby is conditional upon the said conditions being properly fulfilled by the Company.

ISSUED at Toronto June 28, 1991.

Richard R. Perdue
Presiding Member

C. W. W. Darling

C. William W. Darling
Member

Proposed Conditions of Approval
Leave to Construct NPS 4 Line - E.B.L.O. 231

a) Subject to Condition (b), Consumers shall comply with all undertakings made by its counsel and witnesses, and shall construct the transmission line and shall restore the land according to the evidence of its witnesses at this hearing.

b) Consumers shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Consumers shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed forthwith after the fact.

c) Consumers shall furnish the Board's designated representative with every reasonable facility for ascertaining whether the work has been, and is being, performed in accordance with the Board's Order.

d) Consumers shall file with the Board's designated representative, notice of the date on which the installed transmission line is pressure tested within one month after the test date.

e) Both during and after the construction, Consumers shall monitor the effects upon the land and the environment, and shall file ten copies of a final monitoring report in writing with the Board. The final monitoring report shall be filed within 15 months of the in-service date.

f) The final monitoring report shall describe the implementation of Conditions (a) and (b), if any, and shall include a description of the effects noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the construction upon the land and the environment. This report shall describe any outstanding concerns of landowners.

g) The final monitoring report shall describe the condition of the rehabilitated right-of-way. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Further, the final report shall include a breakdown of external costs incurred to date for the authorized project, with items of cost associated with particular environmental measures delineated and identified as pre-construction related, construction related and restoration related. Any deficiency in compliance with undertakings in paragraph (a) shall be explained.

h) Consumers shall give the Board's designated representative and the Chairman of the Ontario Pipeline Coordinating Committee ("OPCC") 10 days written notice, in advance of the commencement of the construction of the transmission line.

i) Consumers shall file with the Board's designated representative "as-built" drawings of the transmission line; such drawings shall indicate any changes in route alignment.

j) Within 12 months of the in-service date, Consumers shall file with the Board a written Post Construction Financial Report. The Report shall indicate the actual capital costs of the project and shall explain all significant variances from the estimates adduced in the hearing.

k) The Leave to Construct granted herein terminates 12 months from any Board order authorizing Leave to Construct.

l) Consumers shall designate one of its employees as project engineer who will be responsible for the fulfilment of undertakings on the construction site. Consumers shall provide the name of the project engineer to the Board. Consumers shall prepare a list of the undertakings given by its witnesses during the hearing and will provide it to the Board for verification and to the project engineer for compliance during construction.

m) Where properties or structures exist within 200 metres of the pipeline and blasting is necessary, Consumers shall:

i) use restricted blasting techniques by ensuring that all charged areas are covered with blasting mats to eliminate fly rock;

ii) have the vibrations from blasting operations monitored and measured by a vibration measurement specialist;

iii) notify all property owners within 200 metres of the easement of the proposed blasting in writing one week prior to the blasting and confirmation (if necessary) of the actual day or days on which blasting will occur;

iv) have buildings within 200 metres of the easement checked by an independent examiner before and after operations to check for problem areas.

n) Where blasting is required, the well condition and water quality of all wells within 30 metres of the pipeline shall be tested before and after blasting operations.

o) Commencing on the anniversary date of the loan, Consumers Gas shall file annually with the Board a revised schedule of the forecast amortization of the Deep River loan similar to M2.3.1. In addition Consumers Gas shall also provide a schedule showing the actual to forecast number of residential and commercial customer attachments to date and the funds received from these customer classes.

DATE: 20060721
DOCKET: C44333

COURT OF APPEAL FOR ONTARIO

LASKIN, BORINS and JURIANSZ JJ.A.

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B E T W E E N :	)	
NATURAL RESOURCE GAS LIMITED	)	Alan Mark and Jennifer Teskey for the appellant
Appellant	)	
- and -	)	
ONTARIO ENERGY BOARD	)	Glenn Zacher for the respondent
Respondent	)	
	)	Heard: April 28, 2006

On appeal from the order of the Divisional Court dated April 21, 2005.

JURIANSZ J.A.:

I. Introduction

[1] Natural Resource Gas Limited ("NRG") appeals from a decision of the Divisional Court dated April 21, 2005, dismissing its appeal of the Review Decision of the Ontario Energy Board (the "OEB") dated April 19, 2004.

[2] NRG purchases gas from producers and distributes it to its customers at rates regulated by the OEB. Because of an accounting error, NRG had unrecorded costs of purchasing gas in the amount of $531,794 during the period from October 1, 2002 to December 31, 2003. Had these costs been recognized, they would have been passed on to NRG's customers in the normal course. After an initial unsuccessful application, NRG made a second application to the OEB on January 20, 2004 in which it sought authorization to record the unrecorded costs as a debit as of January 1, 2004 and an order allowing the recovery of the unrecorded costs by increasing its rates over a twelve month period commencing May 1, 2004. The OEB's Review Decision on that application is the subject of this appeal.

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[3] In that decision, the OEB found the unrecorded costs were material and had been prudently incurred and therefore NRG should be permitted to recover them. The OEB also decided that NRG's recovery of the costs would be deferred over three years to minimize rate volatility to customers. Then, in what gives rise to this appeal, the OEB went on to decide that NRG would not be allowed to recover any of its regulatory costs or the interest charges associated with the deferral of the recovery of the unrecorded costs.

[4] NRG contends that the interest and regulatory expenses result not from the accounting error but from the OEB's decision to defer recovery the unrecorded costs. NRG submits that since the OEB decided that the unrecorded costs were prudently incurred, it follows that the expenses that are associated with the OEB's decision to defer recovery are also prudently incurred. NRG asserts that as a matter of law it would not be "just and reasonable" to deny their recovery.

[5] I would dismiss the appeal because the OEB's decision satisfies the applicable standard of review: reasonableness.

II <u>Issues on Appeal</u>

1. What is the standard of review that applies to the OEB's decision?
2. Did the OEB commit reversible error by denying NRG recovery of its regulatory costs and interest charges?

III <u>Standard of Review</u>

[6] The Divisional Court applied a standard of reasonableness: "[I]n view of the lack of a privative clause, the OEB's disposition attracts at least a standard of reasonableness." NRG submits the Divisional Court erred and that the proper standard of review of the OEB's decision in this case is correctness.

[7] In two recent decisions, *Graywood Investments Ltd. v. Toronto Hydro-Electric System*, [2006] O.J. No. 2030 (C.A.) and *Enbridge Gas Distribution Inc. v. Ontario (Energy Board)*, [2006] O.J. No. 1355 (C.A.), this court has considered the standard of review of decisions of the OEB.

[8] In *Enbridge*, while the result did not turn on the standard of review, Doherty J.A. did note (at para. 17) that the OEB had advanced a "forceful argument that the standard of review should, at the highest, be one of reasonableness".

[9] In *Graywood*, MacPherson J.A. recognized the expertise of the OEB in general (at para. 24):

> First, the OEB is a specialized and expert tribunal dealing with a complicated and multi-faceted industry. Its decisions are, therefore, entitled to substantial deference.

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[10] In order to take this case outside the application of this general conclusion, NRG must establish that the nature of the question in dispute and the relative expertise of the OEB regarding that question are different in this case than in *Graywood*.

[11] *Graywood* concerned a dispute as to whether the parties had agreed that Toronto Hydro would install an electricity distribution system in a Graywood building project before November 1, 2000. This case concerns whether the OEB's decision to deny recovery of certain regulatory and interest expenses is "just and reasonable". I am satisfied the nature of these questions is sufficiently different that it is necessary to address the standard of review that applies in this case afresh. That *Graywood* was not available to the parties when this case was argued provides additional reason to do so.

[12] Determining the applicable standard of review requires a pragmatic and functional consideration of four factors:

> i) the existence of a privative clause;
>
> ii) the expertise of the tribunal;
>
> iii) the purpose of the statute as a whole, and the provision in particular; and
>
> iv) the nature of the question in dispute.
>
> *Pushpanathan v Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, at paras. 29-38.

[13] These factors, in my view, need not be analysed separately or in any particular order. I address all four factors in the following general discussion

[14] The OEB derives its authority from the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Sched. B (the "*Act*").

[15] The objectives of the OEB with respect to gas regulation are set out in section 2 of the *Act*:

> 2. The Board, in carrying out its responsibilities under this or any other Act in relation to gas, shall be guided by the following objectives:
>
> > 1. To facilitate competition in the sale of gas to users.

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2. To protect the interests of consumers with respect to prices and the reliability and quality of gas service.

3. To facilitate rational expansion of transmission and distribution systems.

4. To facilitate rational development and safe operation of gas storage.

5. To promote energy conservation and energy efficiency in a manner consistent with the policies of the Government of Ontario.

5.1 To facilitate the maintenance of a financially viable gas industry for the transmission, distribution and storage of gas.

6. To promote communication within the gas industry and the education of consumers. 1998, c. 15, Sched. B, s. 2; 2002, c. 23, s. 4 (2); 2003, c. 3, s. 3; 2004, c. 23, Sched. B, s. 2.

[16] The OEB also has a broad rule-making regulatory jurisdiction:

44.(1) The Board may make rules,

(a) governing the conduct of a gas transmitter, gas distributor or storage company as such conduct relates to its affiliates;

(b) governing the conduct of a gas distributor as such conduct relates to any person,

(i) selling or offering to sell gas to a consumer,

(ii) acting as agent or broker for a seller of gas to a consumer, or

(iii) acting or offering to act as the agent or broker of a consumer in the purchase of gas;

(c) governing the conduct of persons holding a licence issued under Part IV;

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> (d) establishing conditions of access to transmission, distribution and storage services provided by a gas transmitter, gas distributor or storage company;
>
> (e) establishing classes of gas transmitters, gas distributors and storage companies;
>
> (f) requiring and providing for the making of returns, statements or reports by any class of gas transmitters, gas distributors or storage companies relating to the transmission, distribution, storage or sale of gas, in such form and containing such matters and verified in such manner as the rule may provide;
>
> (g) requiring and providing for an affiliate of a gas transmitter, gas distributor or storage company to make returns, statements or reports relating to the transmission, distribution, storage or sale of gas by the gas transmitter, gas distributor or storage company of which it is the affiliate, in such form and containing such matters and verified in such manner as the rule may provide;
>
> (h) establishing a uniform system of accounts applicable to any class of gas transmitters, gas distributors or storage companies;
>
> (i) respecting any other matter prescribed by regulation. 1998, c. 15, Sched. B, s. 44 (1).

[17] The provision in issue is s. 36 of the *Act.* It prohibits a gas distributor from selling gas or charging for its distribution except in accordance with an order of the OEB and provides that the OEB is not bound by the terms of the contract. It authorizes the OEB to approve or fix "just and reasonable rates" for the sale, transmission, distribution and storage of gas. It allows the OEB, in approving or fixing just and reasonable rates, to adopt any method or technique that it considers appropriate. At the time it provided in part:

> 36 (1) No gas transmitter, gas distributor or storage company shall sell gas or charge for the transmission, distribution or storage of gas except in accordance with an order of the Board, which is not bound by the terms of any contract.

> (2) The Board may make orders approving or fixing just and reasonable rates for the sale of gas by gas transmitters, gas distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate.
>
> ...

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[18] It is clear that the Act constitutes the OEB as a specialized expert tribunal with the broad authority to regulate the energy sector in Ontario. In carrying out its mandate, the OEB is required to balance a number of sometimes competing goals. On the one hand, it is required to protect consumers with respect to prices and the reliability and quality of gas service, but on the other hand, it is to facilitate a financially viable gas industry. The legislative intent is evident: the OEB is to have the primary responsibility for setting gas rates in the province.

[19] The Act does not contain a privative clause. Section 33 provides a right of appeal to the Divisional Court from an order of the OEB "only upon a question of law or jurisdiction".

[20] NRG would characterize the question at issue as one of law, namely, the definition of the phrase "just and reasonable" as used in section 36 of the Act. NRG submits that, properly interpreted, the words "just and reasonable" require that a utility be allowed to recover all its legitimate, prudently incurred costs. NRG argues that the OEB, having found that the unrecorded costs were prudently incurred but not initially recognized because of an accounting error, cannot disallow interest costs that result not from the accounting error, but from the OEB's decision to defer recovery over three years.

[21] The OEB suggests that the question is one involving the manner in which the OEB exercised its discretion in fixing NRG's rates.

[22] The Divisional Court described the nature of the question in this way:

> The question before the Board was therefore not simply whether recovery of costs prudently incurred should be allowed, as the appellant characterized it. The matter was compounded by the added issue of how to deal with the accumulation of costs caused by the appellant's inadvertence. The Board determined that customers must pay the prudently

> incurred unrecorded costs of the appellant, but the impact of recovery of the accumulated total should be ameliorated by allowing recovery over three years. The accumulated cost of the time over which recovery from customers would be required and the appellant's regulatory costs ... must be borne by the appellant. That issue was not a question of law but one involving fact-finding, policy considerations, rate-setting expertise, and law.

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[23] I agree. While the question does involve the meaning of the phrase "just and reasonable", it requires the application of that phrase to the particular and unusual facts of this case. The question is one of mixed fact and law and involves policy considerations as well. The OEB possesses greater expertise relative to the court in determining the question.

[24] Consequently, I conclude that the OEB's decision is reviewable on a standard of reasonableness.

IV <u>Is the Decision in This Case Reasonable?</u>

[25] The Supreme Court of Canada, in *Law Society of New Brunswick v. Ryan*, [2003] S.C.R. 247, explained (at 270) what the reasonableness standard requires of a reviewing court:

> A decision will be unreasonable only if there is no line of analysis within the given reasons that could reasonably lead the tribunal from the evidence before it to the conclusion at which it arrived. If any of the reasons that are sufficient to support the conclusion are tenable in the sense that they can stand up to a somewhat probing examination, then the decision will not be unreasonable and a reviewing court must not interfere.

[26] NRG submits that, as a matter of law, rates that deny utilities recovery of their legitimate prudently incurred costs cannot be "just and reasonable". Rates must be "just and reasonable" to utilities as well as to consumers. Utilities cannot be expected to provide service if they are not allowed to recover their costs and a fair return.

[27] NRG relies on the decision of the Federal Court of Appeal in *TransCanada Pipelines Limited v. National Energy Board*, [2004] F.C.J. No. 654 (C.A.). Under its governing legislation, the National Energy Board's authority to determine just and reasonable tolls, like that of the OEB, is not limited by any statutory directions. Rothstein J.A. indicated that the impact on customers or consumers could not be a factor

in the determination of the utility's cost of equity capital. However, any resulting increase could be so significant that it would be proper for the Board to phase in the tolls over time provided there was no economic loss to the utility. He said (at para. 43), "In other words, the phased in tolls would have to compensate the utility for deferring recovery of its cost of capital."

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[28] I do not read the OEB's decision to be inconsistent with the proposition that a utility must be allowed to recover all of its prudently incurred costs. The OEB, upon concluding that the unrecorded gas costs had been prudently incurred, allowed NRG to recover them. However, the OEB did not accept the premise of NRG's position on this appeal — that if the unrecorded gas costs were prudently incurred, it must logically follow that the regulatory costs to recover them and the interest costs associated with the deferral of their recovery were also prudently incurred. Rather, the OEB found the accumulation of these costs was attributable to NRG's failures to properly record them and to discover its error promptly:

> We are surprised and disappointed with the time that it took NRG to realize that its PGCVA mechanism was incorrect, which exposed the utility and its customers to unnecessary risk and created a difficult situation for the customers and the Board. However, we accept that the misrecording was the result of error, not a purposeful action by NRG.

[29] The OEB went on to observe:

> Had NRG recorded the gas cost variances properly in the PGCVA, the present conundrum would have been avoided.
>
> ... we find the NRG's error has resulted in a substantial and avoidable accumulation of potential customers' charges, through no fault of the customers.

[30] These factual findings of the OEB are not open to question on appeal. In light of these findings, the OEB said, "[W]e must therefore look for a balance". The OEB struck that balance in the following terms:

> Considering the need for NRG to recover its prudently incurred unrecorded gas costs and mitigating the impact on customers, as well as not creating undue inter-generational inequity, we find that a reasonable balance is recovery of the $531,794 amount over a three year period, in equal portions, without interest.

[31] The OEB went on to say that NRG could not recover its regulatory costs incurred in the proceeding.

[32] On my reading, the OEB took the view that NRG's regulatory costs were not prudently incurred. That view is reasonable. But for NRG's accounting error and the delay in recognizing it, NRG would not have had to incur costs to seek and obtain the OEB's decision to permit recovery of the unrecorded costs.

[33] NRG emphasizes that it did not seek recovery of any interest charges from the time the costs were not recorded to the date of the OEB's decision finding the costs to have been prudently incurred. Therefore it submits that the interest charges it claims are the direct result of the OEB's decision to rate-smooth and not of NRG's accounting error.

[34] In my view, it was open to the OEB to consider the underlying as well as the direct cause of the interest charges. The OEB said, "It is also our view that customers should not be burdened by any interest charges that would not have accrued had the customers been presented with the appropriate timely billing". While the interest charges directly result from the OEB's decision to defer their recovery, the OEB would not have faced the situation that prompted that decision "had NRG recorded the gas costs variances properly" and there had been no "substantial and avoidable accumulation of potential customers' charges". Rather, the "present conundrum could have been avoided".

[35] The line of analysis from the OEB's findings of fact to the conclusion it reached is reasonable. It's balancing of the various considerations and interests before it lies at the heart of its function and expertise. Its reasons withstand a probing analysis.

V **Disposition**

[36] I would find that the OEB's decision was reasonable and dismiss NRG's appeal.

[37] The parties indicated they would make efforts to resolve the issue of costs. If they are unable to do so they make written submissions through the court's senior legal officer.

"R.G. Juriansz J.A."
"I agree J. Laskin J.A."
"I agree S. Borins J.A."

RELEASED: July 21, 2006

2006 CanLII 24440 (ON CA)

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Ontario Energy Board

Ontario

In the matter of
a hearing respecting
contract carriage arrangements
on
The Consumer's Gas Company Ltd's,
I.C.G. Utilities (Ontario) Ltd's,
and
Union Gas Limited's
Ontario Distribution Systems

E.B.R.O. 410

E.B.R.O. 411

E.B.R.O. 412

REASONS FOR DECISION

Volume I

REASONS FOR DECISION

E.B.R.O. 410-II
E.B.R.O. 411-II
E.B.R.O. 412-II

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

AND IN THE MATTER OF subsection 13(5) and subsection 19 of the said Act;

AND IN THE MATTER OF a hearing to inquire into, hear and determine certain matters relating to contract carriage arrangements on The Consumers' Gas Company Ltd.'s, ICG Utilities (Ontario) Ltd's and Union Gas Limited's Ontario distribution systems.

BEFORE: R.W. Macaulay, Q.C.
Chairman

J.C. Butler
Vice-Chairman

D.A. Dean
Member

M. Jackson
Member

C.A. Wolf, Jr.
Member

March 23, 1987

ISBN 0-7729-2238-1
ISBN 0-7729-2239-X

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ISBN 0-7729-2239-X

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REASONS FOR DECISION

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4. LEGAL MATTERS

Introduction

4.1 This chapter deals with the three main legal issues and proposals for legislative change.

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Part B Compelling Service and Approval of Contracts

Introduction

4.57 The issues in this section are whether the Board has the jurisdiction to order that LDCs provide a given service and to approve contracts.

4.58 The Board dealt with these issues in the Interim Decision in paragraphs 9.107 to 9.112 and 9.24 to 9.30. The Board held that rates include more than monetary terms and include many conditions of service. The Board has the jurisdiction to determine or approve any term of a contract which is directly or indirectly rate-related. The Board found that it had the jurisdiction to review the terms of any transportation contract to ensure that the contracts were not imprudent or contrary to the public interest. The Board did not decide whether it had the power to order service at that time because there were no instances where such an issue had arisen. However, the Board did state, at para. 9.112:

> ... that the overall scheme of the legislation in Ontario implicitly confers on it the jurisdiction to require service to a customer that qualifies for such service.

The Board's Opinion

4.59 The Board finds that it has the power to compel the provision of services by an LDC to any qualifying customer, including entry into a Board-specified contract. This is part of the inherent jurisdiction which the Board has as a regulator of gas monopolies.

4.60 It is also the opinion of the Board that it can require Board approval of contracts between an LDC and any other person, both as a prerequisite to entry and ex post. Any contract between an LDC and another party for the sale, transmission, storage, or metering etc. of gas affects the costs and revenues of the LDC; the Board finds that such contracts are reviewable through the Board's power to determine just and reasonable rates.

4.61 To suggest that the Board can review rate terms but not other conditions of service is to ignore the fact that they are two sides of the same equation. The Board cannot review the fairness of prices charged unless it can review the level and nature of service provided. Similarly, the Board cannot review the degree to which monopolists are fulfilling their public stewardship unless it can review discriminatory practices of LDCs between their customer classes or customers within a class.

4.62 This concern is accentuated because LDCs are now competing with brokers for sales as well as controlling services essential to successful brokerage sales or direct purchases. The Board, as part of its inherent public interest jurisdiction, must be able to review and compel adjustments to the conduct of LDCs in their position of dominance.

Why the OEB May Compel Service and Approve Contracts

4.63 The Board's opinion is that it has the jurisdiction to compel service by a LDC which refuses to co-operate with a broker or direct purchaser, and to require Board approval of contracts, is based upon:

- The OEB Act providing the mechanisms to accomplish this role.
- The doctrine of jurisdiction by necessary implication;
- The inherent role of a regulator;
- The role of the OEB in Ontario;

The Mechanisms to Approve Contracts and Compel Service

4.64 The first factor leading this Board to find that it has the jurisdiction necessary to approve contracts and compel service is that the Board can utilize its existing powers to effect the necessary regulation within the present statutory framework.

4.65 The Board will not at this time attempt to decide the issue of how it will carry out and enforce its power to approve contract terms or compel service. The Board will decide each case on the facts as they arise.

4.66 The Board has the power to set just and reasonable rates under section 19. The Board may initiate a review of the rates of a LDC under subsection 19(12) of the OEB Act. This power to set rates includes all non-monetary but rate-related terms of service. Section 16 of the OEB Act allows the Board to attach whatever terms and conditions it considers proper in the exercise of its jurisdiction. This could include the requirements of information filing, contract approval or entry into service contracts on a fair basis. The Board considers all terms of service to be rate-related. Therefore, should a LDC discriminate in the provision of services at reasonable rates, the Board would have the power to set rate/service combinations which the LDC must provide. Any rate order could be made conditional upon the LDC following procedures which the Board set out. The Board could also fix rates and corresponding terms of service to facilitate the provision of services to a broker or direct purchaser who cannot reach an agreement with an LDC upon application to the Board.

4.67 Board orders are enforceable under the OEB Act and the Statutory Powers Procedure Act, R.S.O. 1980, c. 484. Violation of an order could lead to the revocation of the LDC's ability to charge rates for its services or to an injunction to force the provision of those services. It is also an offence under section 34 of the OEB Act to contravene any provision of that Act or any Board order.

Jurisdiction by Necessary Implication

4.68 The doctrine of jurisdiction by necessary implication is explained in 36 Halsbury 3rd ed., page 436, para. 657:

> The powers conferred by an enabling statute include not only such as are expressly granted but also, by implication, all powers which are reasonably necessary for the accomplishment of the object intended to be secured.

4.69 This doctrine has been applied in Canada to ensure that regulatory tribunals have the jurisdiction necessary to accomplish their mandates.

4.70 In Re Interprovincial Pipeline Ltd. and National Energy Board (1977), 78 D.L.R. (3d) 401, the

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Federal Court of Appeal had to decide whether an NEB order for the production of documents was within the NEB's jurisdiction, although the NEB did not have express statutory authority to make the order. The Court looked beyond the exact words of the statute to its purpose. It found that the necessary jurisdiction to make such an order ought to be implied since such an order was clearly in furtherance of the legislative purpose and was necessary to enable the Board to function.

4.71 This same doctrine of jurisdiction by necessary implication was pleaded by the successful parties in Re Canadian Broadcasting League and Canadian Radio-Television Commission et al (1982), 138 D.L.R. (3d) 512. Here the Federal Court of Appeal accepted the argument that despite the absence of a statutory provision enabling the CRTC to regulate rates of cable companies, the authority to do so should be found to exist as a natural and necessary part of the CRTC's control of a monopoly in order to achieve the legislative objectives.

4.72 In Ref. Re National Energy Board Act (1986), 19 Admin. L.R. 301 (F.C.A.), it was argued that the NEB had jurisdiction by necessary implication to award costs. In rejecting the submission, the Court imposed two limitations on the doctrine. First, it must be a matter of necessity that the jurisdiction exist for the regulator to accomplish the legislative purpose. This qualification is not met if the tribunal can and has accomplished this purpose without this jurisdiction. Second, the jurisdiction sought must not be jurisdiction to do an act which Parliament clearly addressed its mind to, as would be indicated by past conduct, since to do so would be to usurp the function of Parliament.

4.73 The doctrine of jurisdiction by necessary implication should be implied when:

- the jurisdiction sought is necessary to accomplish the objectives of the legislative scheme and is essential to the Board fulfilling its mandate;

- the enabling act fails to explicitly grant the power to accomplish the legislative objective;

- the mandate of the Board is sufficiently broad to suggest a legislative intention to implicitly confer jurisdiction;

- the jurisdiction sought must not be one which the Board has dealt with through use of expressly granted powers, thereby showing an absence of necessity; and

- the Legislature did not address its mind to the issue and decide against conferring the power upon the Board.

The Inherent Role of a Regulator

4.74 The third factor upon which the Board's ability to compel service and approve contracts is based is the inherent role of a regulator. This underlies the invocation of the doctrine of jurisdiction by necessary implication to ensure that the Board has the power to approve contracts and compel service. This doctrine attempts to ensure that a regulator with a broad mandate will have the tools to fulfill that mandate.

4.75 The role of the modern regulatory tribunal evolved from common law courts which entertained claims of improper conduct by common carriers. Canadian jurisprudence recognizes the obligations of a common carrier or provider of a utility service.

4.76 In Red Deer v. Western General Electric (1910), 2 A.L.R. 145 at 152 (Alt. S.C.) the court stated, after reviewing the common law principles relating to common carriers, that:

> ... there is an implied obligation upon the franchise holder to render

> such services or supply such commodities on request and without unfair discrimination to every inhabitant who is ready and willing to pay in advance therefor, and whose place at which the obligation is required to be performed lies along the line of the franchise holder's operations, and who accords to the franchise holder all reasonable facilities to admit of the convenient performance of the obligation. That, in my opinion, is the obligation in general terms.

4.77 Modern rate regulation developed from these common law principles. Technological advances resulted in more natural monopolies with larger scale operations to maximize efficiency. To ensure that rates and services would be fair and reasonable and operate in the public interest, regulatory tribunals such as the OEB were constituted.

4.78 Canadian jurisprudence has recognized the broad mandate which the modern regulator of utilities has been given. For example, in Re T.A.S. Communication Systems Ltd. and Newfoundland Telephone Company (1983), 2 D.L.R. (4th) 647 at 649, the Newfoundland Court of Appeal summarized the purpose of modern regulatory schemes as follows:

> The Public Utilities Act [R.S.N. 1970], as with similar statutes in all other Canadian jurisdictions, was enacted

> for the purpose of controlling and regulating companies providing essential services ... in order to ensure that those services are properly and fairly provided to the public, and that the charges for such services are fair and reasonable.

4.79 The role of the regulator is not simply to set rates to provide a fair return after legitimate costs of service. Rates must be set in relation to the expected level and quality of service; service must be provided in a non-discriminatory fashion.

4.80 As Webber stated in Principles of Public Utility Regulation, at page 101:

> The grant of special privileges to public service corporations imposed upon them certain obligations and public duties. They are required:
>
> (1) To supply reasonably adequate facilities
> (2) To render service on reasonable terms
> (3) To refrain from unjust discrimination
>
> The function of the state in utility regulation is to prescribe rules that will attain certain objectives.
>
> (1) The insurance of fair remuneration to private property used in the public service
> (2) The prevention of extortion
> (3) The securance of substantial equality of treatment under similar circumstances

(4) The promotion of public safety, good order, and convenience

4.81 Webber further stated, with the support of State ex rel. Wood v. Consumers' Gas Trust (1901) 61 Ne 674, that:

> The common and equal right of the public to reasonable service at reasonable compensation governs all situations where public service is involved. No statute is deemed necessary to aid the courts in holding such to be the law.

4.82 Webber is supported by other authorities on regulatory law such as Jones, Cases and Materials on Regulated Industries (2nd ed, 1976) at page 288, and A.J.G. Priest in his work, Principles of Public Utility Regulation (1969), concerning the service obligation (pages 227-46) and the prohibition against discrimination (page 285 and pages 300-311).

The Role of the OEB

4.83 The public interest mandate given to the Board in the OEB Act is the fourth factor which leads this Board to conclude that it can compel service and approve contracts. This mandate is premised on a legislative intention to grant the Board the necessary jurisdiction to regulate the natural gas industry in Ontario.

4.84 Section 64 provides that the OEB Act prevails in the event of a conflict with any general or special Act. Section 13 grants the Board the power to determine all questions of fact and law within its jurisdiction (subsection 1) and grants the Board exclusive jurisdiction over all matters in which it has jurisdiction (subsection 6). The legislative intent was to create an administrative, regulatory and adjudicative tribunal to oversee the energy industry, particularly the natural gas industry, in Ontario.

4.85 This broad mandate was discussed in Union Gas v. Dawn (supra); the Divisional Court stated at page 625:

> ... it is clear that the Legislature intended to vest in the Ontario Energy Board the widest powers to control the supply and distribution of natural gas to the people of Ontario "in the public interest" and hence must be classified as special legislation.

and, at page 622:

> In my view this statute makes it crystal clear that all matters relating to or incidental to the production, distribution, transmission or storage of natural gas, including the setting of rates, location of lines and appurtenances, expropriation of necessary lands and easements, are

> under the exclusive jurisdiction of the Ontario Energy Board ...
>
> These are matters that are to be considered in the light of the general public interest and not local or parochial interests.
>
> . . .
>
> In the final analysis, however, it is the Energy Board that is charged with the responsibility of making a decision and issuing an order in the public interest.

4.86 The Ontario Divisional Court in Re Ontario Energy Board (1985), 51 O.R.(2d) 333 at 336 stated:

> The jurisdiction of the Ontario Energy Board is very broad. It is charged with the regulatory and quasi-judicial functions covering the entire field of energy within the Province of Ontario.

4.87 This broad mandate and jurisdiction have not been disputed in the courts. The cases of Re Kimpe and Union Gas Ltd. (1985), 52 O.R. 112 and Re Ontario Energy Board (1985), 51 O.R. 333 were cited to the Board as examples of how the courts have limited the Board's jurisdiction to powers expressly delineated in the OEB Act. In the opinion of the Board, these decisions limit the Board's jurisdiction where the Legislature has clearly directed its mind to the issue and decided to withhold a procedural power from the OEB. The procedural powers withheld in these

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two cases were not essential to the accomplishment of the Board's mandate.

4.88 The Board finds that the powers to compel service and approve contracts, are essential to the Board's mandate as a regulator and are not matters explicitly addressed by the Legislature.

4.89 It has been suggested to the Board that the existence of section 22 of the <u>OEB Act</u>, which allows the Board to compel storage service and to approve storage contracts, and section 54 of the <u>PU Act</u>, which allows a person to apply to a court to order an LDC or municipally-owned utility to supply gas, shows that the Legislature directed its mind to whether the Board should have the ability to compel service and approve contracts. In the opinion of the Board, this is not indicative of a legislative intention to preclude the Board.

4.90 When the legislative scheme was enacted it was not foreseen that brokers and direct purchasers would place new demands on the regulatory scheme. The relationship between these parties and LDCs raises the possibility of discriminatory practices or abuse of dominance. Notwithstanding that the Legislature did not address its mind to this possibility, it is necessary that the public interest be served.

COURT FILE NO.: 01-CV-220411CM2
DATE: 20030516

2003 CanLII 45931 (ON SC)

ONTARIO

SUPERIOR COURT OF JUSTICE

B E T W E E N:	)	
GRAYWOOD INVESTMENTS LIMITED	)	*Robert J. Howe* for the Plaintiff
Plaintiff	)	
- and -	)	
TORONTO HYDRO-ELECTRIC SYSTEM LIMITED and ONTARIO ENERGY BOARD	)	*F.J.C. Newbould*, for the Toronto Hydro-Electric System Limited
Defendants	)	
	)	**HEARD:** May 14, 2003

Hoy J.

[1] This is a motion by the defendant Toronto Hydro to dismiss the plaintiff Graywood's claim pursuant to Rule 21.02(3)(a) and (d) and Rule 25.11.

[2] With respect to Rule 21.01(3)(a), Hydro says the Ontario Energy Board (the "OEB" or the "Board") has exclusive jurisdiction over the subject matter of the claim and that therefore this court does not have jurisdiction.

[3] With respect to Rules 21.01(3)(d) and 25.11, Hydro points to an application for judicial review made by Graywood seeking essentially the same relief as in this action

and argues that the continuation of this action, in the face of such application, amounts to abuse of process.

2003 CanLII 45931 (ON SC)

Background

[4] As part of the new regime for the regulation of Ontario energy markets and the participants therein, the OEB published a Distribution System Code. The Code applies to all electricity distributors, including Hydro, and compliance with the Code is a condition of their licences. Charges under the Code are less than the rates in effect under the old regime. The OEB issued a "grandfathering" decision (the "Code Decision"), declaring that the Code did not apply to projects, "that are the subject of an agreement entered into before November 1, 2000." The OEB's Code Decision did not specify that the "agreement" had to be in writing or that it needed the address to address the installation as well as the design aspects of the project.

[5] Graywood is a land developer. In November of 1999, Graywood sent Hydro engineering drawings in respect of its project. Graywood paid a deposit in 1999 and Hydro provided underground electrical design services for the project.

[6] Hydro was of the view that it had an agreement with respect to Graywood's project before November, 2000 within the meaning of the Code Decision and that Graywood was therefore not entitled to the lower Code rates with respect to the installation of the system at the project. Graywood argued that it did not have a formal <u>written</u> agreement with Hydro prior to November 1, 2000 and pointed to the fact a written agreement dealing with the installation component of their arrangement was not signed until November 8, 2000.

[7] Graywood paid the "old rates" under protest.

[8] Graywood asked the OEB to determine that Hydro was contravening its licence and issue an order to Hydro under the *Ontario Energy Board Act,* S.O. 1998, c.15 (the "Act) requiring it to comply with the Code.

[9] The OEB was made aware of Hydro's and Graywood's respective positions, but the hearing Graywood sought was not held.

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[10] On July 25, 2001, the OEB wrote to counsel for Hydro and advised that it had found that an agreement with respect to the project in question had been entered into prior to November 1, 2000, that Hydro was not required to comply with the requirements of the Code with respect to the project and that it would therefore not issue the requested compliance order.

[11] Graywood commenced this action on November 14, 2001, seeking

> (1) a declaration that Graywood and Hydro did not enter into an agreement "for the installation of an underground electrical distribution system" at the project prior to November 1, 2000;
>
> (2) a declaration that the Code applies in respect of the Project; and
>
> (3) return of the excess of payments made the old rates over the new Code rates and an accounting.

[12] Graywood subsequently made application for judicial review of the OEB's July 25, 2001 decision. The grounds for the application included that the OEB erred in concluding that an "agreement" existed and breached Graywood's right to procedural fairness. The application is pending.

Exclusive Jurisdiction

[13] I am satisfied that the OEB has exclusive jurisdiction over the issues raised in this action and that this action should therefore be dismissed.

[14] Pursuant to section 19(6) of the *Act,*

> The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other *Act.*

[15] Section 75(1) of the *Act* provides that if the OEB is satisfied that a licensee is contravening or is likely to contravene its licence, the OEB may order the licensee to comply with its licence.

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[16] The requested determination that Hydro was contravening its licence required the OEB to determine whether there was an agreement between Graywood and Hydro prior to November 1, 2000 within the meaning of the Code Decision*.* Jurisdiction to make that specific determination, likely one of mixed law and fact, was necessarily conferred on the OEB as part of its process of determining whether it was satisfied that Hydro had contravened or was likely to contravene its licence.

[17] Graywood argued that because the OEB did not hold a hearing prior to making its decision that there was an "agreement" and Hydro was therefore not in breach of its licence, and because the OEB issued its decision by way of letter, and not by formal order, it did not have exclusive jurisdiction. Graywood point to sections 19(1), 19(2) and 21(2) of the *Act*, which provide as follows:

> 19(1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and fact.
>
> (2) The Board shall make any determination in a proceeding by order…
>
> 21(2) Subject to any provision to the contrary in this or any other *Act,* the Board shall not make an order under this or any other *Act* until it has held a hearing…

[18] Graywood argues that the OEB only has exclusive authority to determine questions of law and fact in the context of a hearing.

[19] The OEB's position was that Graywood's request to raised a compliance issue and that a hearing was only required if, under s.75(1), it was satisfied Hydro contravened or was likely to contravene its licence and as a result proposed to order Hydro to comply with its licence.

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[20] While Graywood may well have grounds for its application for judicial review, it appears clear that the OEB had exclusive jurisdiction to make the threshold determination under s.75(1) and therefore to determine matters incidental to such determination. I also note that section 19(6) speaks of exclusive jurisdiction in all “matters”: there can be exclusive jurisdiction even though there is not a hearing or a proceeding.

[21] It seems far more appropriate for the regulatory body which drafted the somewhat imprecise language in issue to determine whether or not an arrangement falls within its spirit and intent than this court.

Graywood’s Other Submissions

[22] Assuming that its argument that the OEB did not have exclusive jurisdiction would succeed, and that it would establish that this court had concurrent jurisdiction, Graywood argued that the matter at issue is essentially a private contractual dispute between Graywood and Hydro, that the action does not constitute a collateral attack on the jurisdiction of the OEB and that it should be entitled to seek relief on this contractual dispute in this court. Given my finding that the OEB has exclusive jurisdiction, I will not deal at length with these arguments. I will say, however, that the claims made in this action appear to constitute a direct attack on the OEB’s findings and this matter can in my view be distinguished from the cases of *Rogers Cable T.V. Ltd. v. 373041 Ontario Ltd.* (1996), O.J. No. 2534 (Gen. Div.), varied by [1998] O.J. No. 5125 (C.A.), *Garland v. Consumer’s Gas Co.* (2001), 57 O.R. (3d) 127 (C.A.); [2002] S.C.C.A. No. 53 and *Muchmusic Network, a Division of CHUM Ltd. v. Coast Cable Vision Ltd.,* [1995} B.C.J. No. 81 at 3-4, which Graywood cited.

Summary and Costs

[23] This action shall be dismissed pursuant to Rule 21.01(3)(a) on the ground that this court does not have jurisdiction over the subject matter of the action.

[24] If the parties are unable to agree as to costs, Hydro may provide brief written submissions as to costs, together with a draft bill of costs, prepared in accordance with the costs grid and including particulars as to counsel's year of call and actual hourly rate on this matter, for my consideration within 14 days of the release of this endorsement. Graywood may make brief written submissions to me within 10 days thereafter. Hydro shall not be entitled to make reply submissions.

Hoy J.

Released: May 16, 2003

2003 CanLII 45931 (ON SC)

COURT FILE NO.: 01-CV-22041CM2
DATE: 20030516

2003 CanLII 45931 (ON SC)

ONTARIO

SUPERIOR COURT OF JUSTICE

B E T W E E N:

GRAYWOOD INVESTMENTS LIMITED

Plaintiff

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED and ONTARIO ENERGY BOARD

Defendants

REASONS FOR JUDGMENT

Hoy J.

Released: May 16, 2003

FILE NO.: 40/03
DATE: 20050302

2005 CanLII 4941 (ON SCDC)

ONTARIO

SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

LANE, MOLLOY and POWER JJ.

B E T W E E N:	
ENBRIDGE GAS DISTRIBUTION INC.	*J. L. McDougall Q.C., Jerry H. Farrell*, and *Michael Schafler*, for the Appellant
Appellant	
- and -	
ONTARIO ENERGY BOARD	*Kenneth T. Rosenberg* and *Richard P. Stephenson*, for the Respondent
Respondent	
	HEARD: February 15, 2005

MOLLOY J.:

REASONS FOR DECISION

A. INTRODUCTION

[1] Enbridge Gas Distribution ("Enbridge") appeals from a decision of the Ontario Energy Board ("the OEB" or "the Board") dated December 18, 2002.

[2] Enbridge is a gas distributor and a seller of gas to consumers, and as such is subject to regulation by the OEB under the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15 ("the Act"). The rates Enbridge is permitted to charge to its customers are fixed by the OEB, based on what the OEB deems to be just and reasonable. The OEB must balance fairness to the consumer (in terms of a reasonable price for gas) and fairness to Enbridge and its shareholders (in terms of a

reasonable rate of compensation and profit). Generally speaking, Enbridge would be permitted by the OEB to pass on its costs to the consumer, but only to the extent those costs were prudently incurred.

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[3] Prior to 1996, Enbridge shipped its gas through the TransCanada Pipeline System ("the Trans Canada"). Between 1996 and 1999, Enbridge entered into a series of four agreements with various entities to deliver some of its gas through alternate pipeline routes. These new routes became operational in 2000 and proved to be more costly than the TransCanada route. In mid-2000, Enbridge applied to the OEB for an increase in the rates it could charge to its customers in 2001 in order to reflect this increase in its supply costs. (The OEB referred to the four agreements as Alliance 1, Alliance 2, Vector 1 and Vector 2, and for ease of reference I will do the same.)

[4] The parties entered into a provisional settlement in 2000, which was conditional upon various contentious issues being deferred to be argued at a subsequent Enbridge rates hearing. As a term of the settlement, Enbridge agreed to set up a "Notional Deferral Account" to record, over a ten-month period, the differential between its actual costs for the Alliance/Vector lines and its hypothetical costs if it had used the TransCanada line.

[5] The next year, Enbridge applied for approval of its rates proposed for 2002. One of the contentious issues still remaining to be resolved was whether the costs incurred by Enbridge with respect to the Alliance and Vector lines were "prudently incurred". That issue proceeded to a full hearing before the Board in June 2002.

[6] The Board issued its decision on December 18, 2002. The Board found that Enbridge did not act prudently in incurring the Alliance 1 and Alliance 2 costs and was therefore not permitted to build those costs into the rates it charged. The Board found, however, that the Vector 1 costs were prudently incurred and could be passed on. The Board deferred its consideration of the Vector 2 costs. In the result, Enbridge was not permitted to recover $11 million in costs incurred in respect of Alliance 1 and 2.

[7] The Act provides for an appeal to this court from the decision of the Board, but "only upon a question of law or jurisdiction": s. 33 (1) and (2). Enbridge argues on this appeal that the Board erred in law by failing to apply the correct legal test in determining whether Enbridge acted prudently at the time it entered into the two Alliance agreements. Specifically, Enbridge submits that although the Board articulated the correct legal test, it fell into error when it was influenced by the benefit of hindsight rather than confining itself to a consideration of prudence based solely on circumstances that existed at the time the decisions in question were made.

B. THE PRUDENCE STANDARD

[8] Essentially, a utility is entitled to recover its prudently incurred costs. The test of prudence was first developed in United States jurisprudence, but has since been widely accepted in Canada: *State of Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri*, 262 U.S. 276 (1923) at 289; *British Columbia Electric Railway Co.*

Ltd. v. British Columbia (Utilities Commission), [1960] S.C.R. 837 at 854; *Transcanada Pipelines Ltd. v. Canada (National Energy Board)*, [2004] F.C.J. No. 654 (C.A.) at para. 32; *West Ohio Gas Co. v. Public Utilities Commission of Ohio (No.1)*, 294 U.S. 63 (1935) at 68.

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[9] Before us, and likewise before the Board, there was no dispute between the parties as to the applicability of the prudence standard and the nature of the test. Expenditures are deemed to be prudent, in the absence of some evidence suggesting the contrary. However, costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, are excluded from the legitimate operating costs of the utility in determining rates that may be charged. The examination of whether an expenditure was prudent must be based on the particular circumstances at the time the decision to incur those costs was made. That is so even if in hindsight it is obvious the decision was a bad one. As was stated by the United States Court of Appeals (First Circuit) in *Violet v. FERC*, 800 F. 2d 280 at 282 (1st Cir. 1986):

> In an industry that combines long lead times for plant construction with wide fluctuations in supply and demand, constant changes in the regulatory environment, and unpredictability in the availability and price of alternative sources of fuel, some projects that seem prudent at the time when costs are incurred may appear, some years later, in hindsight, to have been unnecessary or inadvisable. The prudence of the investment must be judged by what a utility's management knew, or could have known, at the time the costs were incurred. (citations omitted)

[10] The parties also agree that the Board in this case correctly defined the prudence standard at paragraph 3.12.2 of its decision as follows:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

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C. THE DECISION OF THE BOARD

[11] The Reasons of the Board are extensive, covering 216 pages. For purposes of this appeal, it is unnecessary to review those Reasons in detail, as there is no real issue with respect to the facts. The portion of the Reasons dealing with the Alliance/Vector issues runs from pages 27-72. However, the actual findings of the Board commence at page 62. First, the prudence test is defined (see preceding paragraph). Next, the Board examined the presumption of prudence and whether it was rebutted. The Board noted the argument made by Enbridge that it was unnecessary to consider this aspect of the test as Enbridge conceded a prudence review was appropriate. However, the Board determined that it would nevertheless be useful to actually rule on the point.

[12] There was evidence before the Board that Enbridge's corporate parent, Enbridge Inc., held an equity interest in both the Alliance and Vector pipelines at the time Enbridge entered into the agreements in question. The Board found that the fact Enbridge Inc. may have profited as a result of Enbridge entering into these contracts was not sufficient evidence to establish that the arrangements were not therefore prudent. However, the Board noted that the interests of Enbridge Inc. and Enbridge might not completely coincide and found the evidence of this ownership interest was "sufficient to overcome the presumption of prudence and invite further inquiry by the Board": paragraph 3.12.11 of the Reasons.

[13] The Board noted that it is permissible to use hindsight in determining the threshold issue as to whether the presumption of prudence is rebutted. In this regard, the Board considered the balance in the Notional Deferral Account, which favoured the traditional TransCanada pipeline, and held this evidence would suggest that the prudence of Enbridge's decisions to use the Alliance and Vector routes should be examined.

[14] The Board then concluded (at paragraph 3.12.13) that "the presumption of prudence has been overcome and that there are reasonable grounds to inquire into the prudence of [Enbridge's] decisions to enter into long term transportation arrangements with the Alliance and Vector pipelines."

[15] The Board then proceeded (from pages 65 to 69) to consider whether Enbridge made prudent decisions to enter into each of the four contracts, examining the circumstances of each decision under a separate subject heading. At this point, the onus would be on Enbridge to establish its prudence in entering into each of the four contracts.

[16] Under the heading "Alliance 1" (paragraphs 3.12.14 to 3.12.21), the Board considered the justifications advanced by Enbridge for its decision in 1996 to enter into this contract. The Board focused on what was referred to as the "Otsason Memo", based on Enbridge's testimony that the memo summarized all of the factors Enbridge took into account in making this decision. The Board described the Otsason Memo as a "rudimentary financial analysis". The Board then took issue with a number of conclusions in the Otsason Memo (the content of which is not

relevant for purposes of this appeal) as well as noting Enbridge's failure to consider the full range of reasonable alternatives. The Board then concluded (at paragraph 3.12.23) that it was "not satisfied that [Enbridge's] decision to enter into the Alliance 1 contract in 1996 was prudent".

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[17] For purposes of this appeal, Enbridge does not take issue with this portion of the Board's Reasons in respect of Alliance 1, except for the Board's reference in paragraph 3.12.20 to the fact that a risk identified in the Ostason Memo had in fact materialized. Mr. McDougall, for Enbridge, submits that this reference illustrates error by the Board in using hindsight to evaluate prudence. The relevant paragraph of the Reasons states:

> 3.12.20 One of the disadvantages identified in the Ostason Memo was the risk of in-service delays for the Alliance pipeline. This risk in fact materialized; the in-service date was delayed by over one year from November 1999 to December 2000. (emphasis added)

[18] Under the heading "Alliance 2", the Board held that all of its concerns with respect to Alliance 1 were equally applicable to the 1997 decision to enter into the Alliance 2 contract, and also noted two additional concerns. The Board then concluded (at paragraph 3.12.27) that it was not satisfied that Enbridge's 1997 decision to enter into the Alliance 2 contract was prudent.

[19] The Board next considered Vector 1 (paragraphs 3.12.28 to 3.12.31) and concluded that Enbridge's decision to enter into that contract in 1999 was in fact prudent.

[20] The last portion of the Board's consideration of prudence falls under the heading "Vector 2" (paragraphs 3.12.32 to 3.12.33). The Board started by noting that Enbridge had "advised" the Board that it entered into the Vector 2 contract in order to replace its expiring capacity on the TransCanada pipeline. The Board then found (at paragraph 3.12.32) that Enbridge "did not provide the Board with sufficient evidence and analysis, including alternatives, to justify this decision." The Board noted that the Vector 2 decision was independent from and unrelated to the Alliance 1 and 2 and Vector 1 contracts. The Board then stated, at paragraphs 3.12.33 to 3.12.34:

> 3.12.33 …. In addition, the Board notes that the costs consequences of the Vector 2 contract were not included in the calculation of the Notional Deferral Account, which is a key element of the Board's prudence review of the Alliance and Vector arrangements. (emphasis added)
>
> 3.12.34 As a result, the Board is not prepared at this time to make a determination of the prudence of [Enbridge's] decision to enter into the Vector 2 contract.

[21] Mr. McDougall relies on this passage as a further illustration of the Board's improper use of hindsight in evaluating prudence.

[22] The balance of the Board's decision on Alliance and Vector is devoted to "Relief and Remedies" at pages 70-71 of the Reasons and is not relevant for purposes of this appeal.

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D. STANDARD OF REVIEW

[23] It is well recognized that the applicable standard of appellate review is to be determined on a "functional and pragmatic approach" based on consideration of four factors: (1) the existence or absence of a privative clause in the enabling statute of the administrative tribunal; (2) the expertise of the tribunal relative to the court; (3) the purpose of the legislation; and (4) the nature of the problem: *Pushpanathan v. Canada (Minister of Citizenship and Immigration)* (1998), 160 D.L.R. (4th) 193 (S.C.C.) at 208-215; *Ryan v. Law Society of New Brunswick* (2003), 223 D.L.R. (4th) 577 (S.C.C.) at 587-592, paras. 27-42; *Dr. Q. v. College of Physicians & Surgeons (British Columbia)* (2003), 223 D.L.R. (4th) 599 (S.C.C.) at 609-13.

[24] In this case, the expertise of the tribunal in regulatory matters is unquestioned. This is a highly specialized and technical area of expertise. It is also recognized that the legislation involves economic regulation of energy resources, including setting prices for energy which are fair to the distributors and suppliers, while at the same time are a reasonable cost for the consumer to pay. This will frequently engage the balancing of competing interests, as well as consideration of broad public policy. That is why courts have accorded considerable deference to the Board and applied standards of reasonableness *simpliciter*, or even patent unreasonableness when reviewing decisions which engage the Board's expertise: *Consumer's Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (Div.Ct.); *Graywood Investments Limited v. Ontario (Energy Board),* [2005] O.J. No. 345; *ATCO Electric Ltd. v. Alberta (Energy and Utilities Board)*, [2004] A.J. No. 823 ("ATCO No. 1") (C.A.); *ATCO Electric Ltd. v. Alberta (Energy and Utilities Board),* [2004] A.J. No. 906 ("ATCO No.2") (C.A.).

[25] However, the case before us involves a pure question of law. There is an appeal as of right to this court on a question of law, and there is no applicable privative clause. Further, the nature of the legal issue involved does not engage the expertise of the tribunal, *vis a vis* the court. The test is well understood and was correctly defined by the Board. The only issue is whether, in applying that test, the Board took into account an impermissible factor. That is not a situation of mixed fact and law, but rather an alleged error in applying the correct legal test. In *Housen v. Nikolaisen*, [2002] 2 S.C.R. 235 at paragraph 27, the Supreme Court of Canada (referring to its own earlier decision in *Canada (Director of Investigation and Research) v. Southam Inc.*, [1997] 1 S.C.R. 748) held as follows:

> 27 Once it has been determined that a matter being reviewed involves the application of a legal standard to a set of facts, and is thus a question of mixed fact and law, then the appropriate standard of review must be determined and applied. Given the different standards of review applicable to questions of law and questions of fact, it is often difficult to determine what the applicable standard of review is. In Southam, supra, at para. 39, this Court illustrated how an error on

a question of mixed fact and law can amount to a pure error of law subject to the correctness standard:

> . . . if a decision-maker says that the correct test requires him or her to consider A, B, C, and D, but in fact the decision-maker considers only A, B, and C, then the outcome is as if he or she had applied a law that required consideration of only A, B, and C. If the correct test requires him or her to consider D as well, then the decision-maker has in effect applied the wrong law, and so has made an error of law.

Therefore, what appears to be a question of mixed fact and law, upon further reflection, can actually be an error of pure law.

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[26] The Supreme Court's illustration applies equally well in the reverse. If the correct test requires the consideration of A, B and C and prohibits the consideration of D, and the decision-maker considers D, that is an error of pure law.

[27] Given the right of appeal and the nature of the issue, in my opinion, the appropriate standard of review in this case is one of correctness. The Board was required to be correct on this point. If, in considering prudence, the Board took into account factors involving the application of hindsight, then it has committed legal error and its decision cannot stand.

E. ANALYSIS

[28] It is important to distinguish between things that can be considered at the stage of deciding if the presumption of prudence is rebutted, and things that can be considered as part of the prudence analysis itself. In considering the application of the presumption, it is acceptable to use the benefit of hindsight. Thus, a decision which turned out to have a bad economic outcome will not be presumed to be prudent, but rather will be subject to an analysis of the surrounding circumstances to determine if it was in fact prudent. In this case, the Board had before it evidence from the Notional Deferral Account as to the extra cost incurred by Enbridge as a result of the Alliance and Vector contracts, over and above what would have been the cost if the TransCanada pipeline had been used. The Board was entitled to use that information in determining the threshold issue as to whether the presumption of prudence was rebutted. It was not entitled to use the information as part of its analysis as to whether the decisions at issue were, or were not, prudent at the time they were made.

[29] The Board in this case was well aware of that distinction. The Board held, at paragraph 3.12.36 of its decision:

> 3.12.36 The Notional Deferral Account was intended as a measure to ascertain whether the cost differential between the old and the new paths was substantial, such that it would raise the issue of whether the presumption of prudence had been overcome. It was not intended as a method of determining the cost

> consequences and any potential disallowance of costs if the Board were to find that entering into the Alliance and Vector agreements were not prudent.

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[30] Notwithstanding the Board's articulation of the proper use of this information, there are two clear references to matters of hindsight in the portion of its reasons dealing with the prudence of Enbridge's decisions.

[31] The first such reference is at paragraph 3.12.20 of the Board's reasons in which the Board refers to delay which occurred from November 1999 to December 2000 in determining whether a decision in 1996 was prudent. The impact of this reference could, however, be minimized since it was made in the context of a risk which Enbridge had identified and took into account in 1996. The impact on the decision would obviously be worse if the Board had been pointing out a delay that had occurred after the fact and had not been predicted or considered back in 1996. Therefore, if the only hint of a hindsight type analysis was this one reference, I would not have serious concerns.

[32] However, the Board's reference to later events in its analysis of the Vector 2 contract (in paragraph 3.12.33) is more troublesome. The Board had already determined that Enbridge "failed to provide sufficient evidence and analysis, including alternatives, to justify this decision." Since the onus was on Enbridge to establish prudence, that would have been sufficient to support a finding by the Board that Enbridge had not discharged that onus and that the extra costs of that decision could therefore not be passed on to consumers. Obviously, the Board was not required to make such a finding, and it was perfectly open to the Board to defer the matter to give Enbridge an opportunity to file additional evidence. However, the reason cited by the Board for deferring the matter was that the cost consequences of the Vector 2 contract had not been included in the calculation of the Notional Deferral Account. The inescapable inference from this is that the Board felt unable, or was unwilling, to make a decision on prudence without this information. However, information as to what the actual costs of the decision turned out to be after the fact, is clearly an application of hindsight and is not permitted as part of the analysis of prudence.

[33] Counsel for the OEB submits that the reference to the Notional Deferral Account relates only to the rebuttal of the presumption of prudence and that the Board was not discussing the use of the financial information as part of its prudence analysis. Rather, he argues, the Board was simply stating it was unable to deal with whether the presumption of prudence applied without the missing information as to actual costs after the fact. I cannot accept that argument. The Board's decision is very logically laid out, as I have discussed above in paragraphs 11 to 22. The Board dealt first with the general test for relevance and then with whether the presumption of prudence was rebutted. It was only after finding the presumption was rebutted that the Board turned to a consideration of each of the four contracts and a determination of prudence in respect of each of them. When the decision is looked at as a whole, it is clear that in paragraphs 3.12.32 to 3.12.34 the Board was dealing with whether the prudence standard had been met for the Vector 2 contract. That is the context in which the Notional Deferral Account is mentioned, and it can only logically be interpreted as referring to the prudence standard.

[34] In any event, it was not necessary for the Board to have information from the Notional Deferral Account in order to deal with the presumption of prudence issue. For the Alliance 1, Alliance 2 and Vector 1 contracts, the Board had three bases upon which the presumption was rebutted:

(i) the concession by Enbridge that the presumption was rebutted and that a prudence review was warranted;

(ii) the potential for conflict of interest because of the ownership interest of Enbridges's parent in the Alliance and Vector pipelines; and

(iii) the substantial extra costs actually incurred as demonstrated by the Notional Deferral Account.

[35] With respect to the Vector 2 contract, the Board did not have the information from the Notional Deferral Account, but it had already determined that the conflict of interest issue alone was sufficient to rebut the presumption and it had the concession from Enbridge that a review of prudence was appropriate in the circumstances. The Board did not need the Notional Deferral Account information to make its decision on the presumption, and indeed had already made that decision in respect of all four contracts at paragraph 3.12.13 of its Reasons.

[36] Counsel for the OEB further argues that since the Board made no decision with respect to Vector 2, its reasoning on Vector 2 is not the subject of this appeal and not relevant to our consideration of whether the Board erred in its analysis of the Alliance contracts. That might well be a valid point if the Board had confined its reasoning in paragraph 3.12.33 to the Vector 2 contract itself. However, the Board referred to the absence of the Deferral Account information for Vector 2 and then commented that this information was "a key element of the Board's prudence review of the Alliance and Vector arrangements". Given the context in which these words appear as well as the actual language used, it seems clear that the Board did in fact consider the actual costs incurred for Alliance as compared to the TransCanada pipeline to be a "key element" in its determination that the Enbridge decision to enter into the Alliance contracts was not prudent.

[37] The Board clearly articulated the correct test for the prudence review and appeared to understand that the prudence review must be based on circumstance that were known, or should reasonably have been known, by management making the decision at the time the decision was made. Because the test is so clearly stated by the Board, I have considered very carefully whether the Board's references to matters of hindsight in paragraphs 3.12.20 and 3.12.33 ought to be considered as innocuous, or related to some other analysis. I cannot reach that conclusion. In my view, the Board must be taken to have meant what it said. There are two clear references to a consideration of events which occurred after the decisions were made in the context of the Board's consideration of the prudence of the decisions. Reading the Board's comments any other way would, in my view, unduly strain the language used, particularly in the context in which those words appear.

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[38] The retrospective application of the prudence test, ignoring the benefit of hindsight, is not an easy task for a decision-maker who is fully aware of the actual financial consequences of a decision. The decision-maker must shut out of his or her mind all knowledge of matters that are not permitted to be taken into account. This is something which is easier to describe than it is to carry out in practice. In this case, the Board described the test correctly, instructed itself not to use hindsight in evaluating prudence, but then slipped in its application of the test and did allow hindsight to creep into its consideration of prudence. That is a fundamental error of law.

F. CONCLUSIONS

[39] There was certainly evidence before the Board upon which it could have reasonably concluded that the Alliance contracts were not prudent. However, it is not possible to determine the extent to which an impermissible line of thinking clouded the Board's determination in this case. This is particularly problematic in that the hindsight considerations involved only the first 10 months of contracts that were to run for a period of 15 years. The appellant is entitled to a decision based on the correct application of the legal test to the relevant facts. In the result, the Board's decision cannot stand and is therefore quashed in so far as it relates to the Alliance 1 and Alliance 2 contracts.

[40] The determination of prudence and the remedies flowing from a determination that a particular decision was or was not prudent are matters within the specialized expertise of the Board. Such determinations are intended under the Act to be the sole province of the OEB and ought not to be made by courts. Accordingly, this matter is remitted back to the OEB for consideration by a differently constituted tribunal.

[41] If the parties are unable to agree on the costs of this appeal, they may be addressed in writing. Counsel for Enbridge is requested to coordinate the timing of the costs submissions and to forward three copies of all of the submissions, preferably bound and indexed, to the Divisional Court office.

MOLLOY J.

I agree:

LANE J.

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I agree:____________________________

POWER J.

Released:

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COURT FILE NO.: 40/03
DATE: 20050302

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ONTARIO

SUPERIOR COURT OF JUSTICE
DIVISIONAL COURT

LANE, MOLLOY and POWER JJ.

B E T W E E N:

ENBRIDGE GAS DISTRIBUTION INC.

Appellant

- and -

ONTARIO ENERGY BOARD

Respondent

REASONS FOR JUDGMENT

MOLLOY J.

Released: March 2, 2005

Ontario
Energy
Board

Ontario

E.B.L.O. 186

IN THE MATTER OF The Ontario Energy Board Act, R.S.O. 1970, Chapter 312, as amended, and in particular sections 38 and 40 thereof;

AND IN THE MATTER OF an application by The Consumers' Gas Company for leave to construct a natural gas pipeline and facilities from the present natural gas pipeline of the Applicant located in the City of Pembroke, through the Township of Stafford, the Township of Alice and Fraser, the Township of Petawawa and the Village of Petawawa to the Canadian Forces Base Petawawa in the County of Renfrew, Province of Ontario.

BEFORE: J. R. Dunn)
Presiding Member)
)
D. M. Treadgold)
Member) April 24, 1979
)
I. B. MacOdrum)
Member)

REASONS FOR DECISION

1. The Application and Hearing

These Reasons for Decision deal with an application dated December 7, 1978 (the "application"), by The Consumers' Gas Company (the "Applicant" or "Consumers'") pursuant to the provisions of The Ontario Energy Board Act (the "Act") and in particular pursuant to sections 38 and 40 of the Act for an order granting leave to construct a natural gas pipeline and facilities (the "extension"), extending from the Consumers' existing 8-inch natural gas pipeline in the City of Pembroke to the Canadian Forces Base Petawawa ("CFB Petawawa"), a total distance of approximately 12.69 miles. Affidavits were filed by the Applicant proving service of the notice of application and the application, and publication of the notice, in accordance with the directions of the Board.

The pre-filed evidence of the Applicant was served on interested parties as well as on the Director, Land Use Co-ordination Branch of the Ontario Ministry of Natural Resources, Toronto; Mr. L. Grenier, Chief, Navigable Waters Protection Branch, Department of Transport, Government of Canada, Ottawa; Mr. L. Bronson, District Manager of the Ontario Ministry of Natural Resources, Pembroke; and Mr. J. M. Childs, District Engineer, Ministry of Transportation and Communications, Ottawa.

The hearing was set down to commence on April 24, 1979, in Toronto and the notice of hearing was published and served on interested parties and government departments and ministries. The hearing was commenced and completed on that date.

Mr. P. Y. Atkinson appeared on behalf of the Applicant and Mr. L. Graholm appeared for the Board.

No answers were filed by any intervenors.

Mr. L. F. Parsons of the Environmental Approvals Branch of the Ministry of the Environment was present and made a brief comment during the course of the hearing.

The Board heard evidence from seven of the Applicant's employees, as follows:

Peter D. Harper	Manager of Consulting Services and Special Studies
Robert Harold Townsend	Manager of the Eastern Region
William Henry Girling	Manager of the Land Department
John Bruce Graham	Regional Manager of Operations, Eastern Region
Alexander M. Houston	formerly, Regional Sales Manager, Eastern Region
Walter Bruce Taylor	Director, Economic Evaluation and Statistics
Fraser Dickson Rewbotham	Manager, Rate Research.

A verbatim transcript of the proceedings was prepared and is available for inspection at the Board's offices. Therefore, the Board does not consider it necessary to set out in detail the evidence and submissions of the Applicant or Board counsel in these Reasons for Decision but will summarize their positions to the extent deemed necessary.

2. Environmental Matters

(a) The Applicant's Position

The Applicant called Mr. Peter D. Harper, who develops and implements company guidelines and specifications for environmental protection, particularly in the areas of pipeline construction, testing and operation. Mr. Harper was responsible for the preparation of the environmental assessment material contained in the Applicant's prefiled evidence (Exhibit 9) and he also testified with respect to the Applicant's discussions with the officials of the Ministry of the Environment. He also answered questions with respect to Exhibit 10, a letter dated April 10, 1979, to Mr. D. D. McLean, Director of Operations, Ontario Energy Board, being a "Supplement to the Pre-filed Evidence with respect to environmental considerations for E.B.L.O. 186". This witness responded to examination with respect to the detailed construction drawings of the proposed pipeline (Exhibit 11A). He testified that these drawings had been modified to reflect environmental considerations raised in discussions with officials of the Ministry of the Environment.

Mr. Harper's testimony also dealt with certain provisions of an environmental nature contained in the Applicant's Contract Specifications - Main and Service Construction 1978 (Exhibit 13).

Mr. Robert Harold Townsend, Manager of the Eastern Region of Consumers', was the senior official who testified on behalf of the Applicant and he, together with counsel for the Applicant, gave certain policy undertakings on environmental matters.

After review of the application and the pre-filed evidence (Exhibit 9) as it pertained to environmental matters, Mr. D. P. Caplice, Director, Environmental Approvals Branch, Ministry of the Environment, wrote a memorandum dated March 16, 1979, (Exhibit 16) to Mr. McLean, of the Board staff. The memorandum was supplied to the Applicant and subsequently meetings were held to discuss it. As a result, the Applicant supplemented its pre-filed evidence on environmental matters with Exhibits 10, 11 and 11A. Mr. Caplice, in a letter to Mr. McLean dated April 20,1979, (Exhibit 17), provided the Ministry's comments on this supplemental material. In that letter Mr. Caplice wrote:

> "I would like to mention that my staff are very pleased with the environmentally-conscious attitude and cooperation expressed by Consumers' Gas. We are hopeful that the lessons learned in this particular application will become standard practice for Consumers' Gas in future applications before the OEB.
>
> "We are now satisfied that the deficiencies previously identified have been adequately dealt with by the company in their latest documentation. We would, however, like to suggest the following inclusions."
> (Exhibit 17, page 1.)

Mr. L. F. Parsons clarified the Ministry's intent in the second sentence of the first paragraph quoted from Exhibit 17 by stating:

> "The Ministry here is interested in seeing the lesson learned in this particular Application applied to all gas and oil companies that make application before the OEB. It wasn't our intention to imply that these lessons only apply to Consumers' Gas. I think it's just a point of clarification." (Transcript, p. 40.)

In response to questioning by Board counsel, Mr. Harper agreed that he had not included in the environmental material an outline of the contacts that had been made with public authorities before and after the filing of the application and he undertook that Consumers' would provide such a list in the future in such environmental reports. Such a list would include the specific public authorities, and persons contacted, the date of the contact and the subject matter of the contact.

In his evidence Mr. Harper indicated that the proposed construction did not require the use of heavy equipment or blasting and that the noise impact would be minimized.

Mr. Harper discussed the process and the rationale for the selection of the route for the extension. In testimony he indicated that all facilities would be below grade except for the pressure control station at CFB Petawawa and a bridge crossing the Petawawa River. With respect to the bridge crossing, Mr. Harper testified that construction of the pipeline across the bridge would be undertaken without any equipment and machinery in the water underneath the bridge. He stated ". . . this crossing can be done entirely from the bridge structure itself".

Mr. William Henry Girling, Manager of the Land Department of Consumers', indicated that approval for the project from the Ministry of Natural Resources was contingent on receiving the approval of the Ministry of the Environment. Since approval from the Ministry of the Environment had been obtained he expected to be receiving approval from the Ministry of Natural Resources. Mr. Atkinson identified Exhibit 17 as the document indicating the approval of the Ministry of the Environment and undertook to file the approval of the Ministry of Natural Resources when received.

At the request of Board counsel, Mr. Townsend as the senior representative of the Applicant at the hearing, was requested to give certain undertakings on environmental matters. The interchange resulting in these undertakings is set out below:

> "Q. I would just like to tie this together with the environmental considerations, Mr. Chairman, by asking Mr. Townsend, as the senior person here for Consumers' whether Consumers' undertakes to construct and test the pipeline and do the clean up and post construction repairs in the manner described in the evidence, including the contract specifications and the construction drawings.
>
> "A. Yes, the company so undertakes. That has been discussed this morning, including the letter of the 20th of April, 1979, which we received a copy of this morning from the Ministry of the Environment, Exhibit 17. We have no problem, we will comply with all of the requests.
>
> "Q. Now, you refer to Exhibit 17; does Consumers also undertake to take measures outlined in the letter which is Exhibit 10? That is the letter from Mr. Harper.
>
> "A. Yes, Mr. Graholm, we have no problem with the letter that we supplied as Exhibit 10. We will live up to its specifications.

"Q. Does Consumers' undertake to take the amelioration and mitigatory measures described in Mr. Harper's environmental study?

"A. Again we have no problem, we will live up to those requests and standards.

"Q. Exhibit 10 refers to a monitoring report, I believe, which will be prepared by Consumers'.

"The Presiding Member: What page is that reference on, Mr. Graholm?

"Mr. Atkinson: Page 4 of the attached memorandum to Exhibit 10, right at the bottom, sir, 1.5.

"The Presiding Member: Right.

"Mr. Graholm: Q. Could you file a copy of that with the Board, Mr. Townsend?

"A. We're talking about the filing of the follow-up monitoring program report?

"Q. Yes.

"A. Yes.

"Q. And, lastly, does Consumers' undertake to comply with the Board's environmental guidelines?

"A. Yes, we have no problem." (Transcript, pp. 21, 22 and 23.)

In his concluding submissions Mr. Atkinson said that Exhibit 17 indicated that the Ministry of the Environment is quite satisfied with the manner in which the Applicant has co-operated with the Ministry and that the deficiencies previously indentified have been adequately dealt with. He continued as follows:

"I would also ask you to take into consideration the undertakings that were made by Mr. Townsend. Those undertakings were of a very serious nature, in my submission, and I do get the impression that Consumers' is perhaps

> leading the pack in terms of the type of evidence that will be filed in the future and the type of co-operation that the Board hopes will occur between the other utilities and the Ministry of the Environment and, indeed, this Board". (Transcript, p. 235.)

(b) Submissions of Board Counsel

Board counsel tendered the correspondence between the Ministry of the Environment and the Board staff which formed Exhibits 10 and 17. Some of the examination of Mr. Harper and Mr. Townsend by Board counsel has already been noted, particularly the undertakings he obtained from both witnesses.

(c) Views of the Board

The Board commends the level of co-ordination and co-operation amongst the Applicant, the affected Ministries of the Government and Board staff. The Board hopes that this will continue in other applications for facilities by this and other applicants.

It appears to the Board from this process, together with the undertakings given by the Applicant during the hearing, that environmental concerns in relation to the proposed project have been and will be adequately met.

3. Engineering Matters

(a) The Applicant's Position

The Applicant currently owns and operates a pipeline (the "existing line") running from the pipeline of TransCanada PipeLines Limited ("TransCanada") near Brockville, north through Smiths Falls, Carleton Place, Almonte, Arnprior and Renfrew and terminating in Pembroke. The existing line has an 8-inch diameter and there is a 4-inch diameter lateral providing gas to Perth. (Exhibit 18.)

Evidence relating to engineering matters was given by Mr. John Bruce Graham, the Regional Manager of Operations for the Eastern Region of Consumers'. He was later joined by Mr. Townsend and Mr. Alexander M. Houston, formerly Regional Sales Manager of the Applicant's Eastern Region.

The existing line is currently designed and operated to receive gas from TransCanada, under steady state conditions, at 650 pounds per square inch gauge ("psig") at Brockville gate station. Maximum flow up the existing line has been 1,050 thousand cubic feet per hour ("Mcf/h"). The line has capacity to supply a further 400 to 500 Mcf/h at Pembroke.

The existing line is not looped. However, sections of it have recently been hydrostatically retested and have been re-rated to permit operation at higher pressures than formerly. To add to the security of the existing line a liquefied natural gas ("LNG") vapourization facility was established at Arnprior in early 1978. Consumers' purchases LNG from Gaz Metropolitain, inc., which is shipped by truck and stored until vapourized at the facility in Arnprior. The plant can gasify LNG at the rate of 230 Mcf/h and has a capacity of 4.2 million cubic feet ("MMcf").

Evidence was led with respect to the potential markets to be served by the extension and this subject will be discussed in more detail in a later section. The result of this evidence was that the potential market on the extension northwest of Pembroke would require a pressure at Pembroke of 149 psig to meet the peak load, with 100 psig, at CFB Petawawa. With the interruptible portion of this load removed, Mr. Graham testified that only between 120-125 psig would be required at Pembroke in order to have 100 psig at CFB Petawawa.

The pressure of 149 psig at Pembroke would transmit 371 Mcf/h to Petawawa which would meet the forecast load of 168 Mcf/h firm service and 203 Mcf/h interruptible service for the central heating plant at CFB Petawawa. Mr. Townsend in his testimony justified the choice of 8-inch diameter pipe, in part, in that it would prevent any restriction of the Applicant's ability to market interruptible gas on days when the extension is not being used to meet peak heating needs.

When it was suggested that without the interruptible market potential the proposed pipeline diameter would be smaller, Mr. Townsend said the extension would not have been proposed without the interruptible market. He added that Consumers' experience together with "good engineering and good management" dictated that the extension should be an 8-inch pipeline. Such a pipeline diameter would provide some potential for growth in interruptible and other loads.

Consumers' anticipates virtually negligible growth in load on the existing line north from Brockville. However, Mr. Townsend noted that a government report indicated the possibility of a ten percent growth in population to the year 2000 in Pembroke. This could lead to some increase in natural gas load.

As a result of this assessment of future load growth in the area served by the existing line and the extension, the Applicant does not anticipate any looping of the existing line within the next ten years.

The security of supply to customers on the extension was discussed by the Applicant's witnesses. If an interruption to service from a line break occurred south of the LNG plant at Arnprior, firm residential customers on the extension could be served indefinitely. If a break occurred north of the LNG plant, with interruptible and firm industrial customers curtailed, Consumers' could serve residential customers beyond the break, according to the Applicant's witness "for 12 to 24 hours on line pack". Mr. Townsend was further asked if that would be sufficient time to repair the line. He replied that the time frame suggested would be sufficient for emergency repairs and that the additional line pack from an 8-inch pipe was one of the Applicant's grounds for favouring it over a 6-inch diameter line.

Mr. Graham testified that in his judgment his construction cost estimate of about $1.5 million may have been high. The cost estimate was prepared before approval from the Ministry of Transportation and Communications for the construction of the crossing of the Petawawa River by attaching the pipeline to the bridge. The witness said that, with the bridge crossing approved and the engineering and preliminary work done in great depth, he believed that the $100,000 contingency item included in his cost estimate for the project was ample although it was slightly less than the ten percent rule of thumb often used for such an allowance.

Mr. Graham, in his direct testimony, stated that the extension will be constructed in compliance with C.S.A. Standard Z184-1975, Gas Pipeline Systems, as well as the Applicant's contract specifications and Standard Practice Manual. He testified that the entire project was designated as construction class 3, as referred to in C.S.A. Standard Z184-1975.

He also stated that the entire project, being the extension and associated distribution facilites, is proposed to be phased over the next three years. The extension, which is the high pressure portion of the project, will be completed in 1979.

(b) Submission of Board Counsel

The major issues touched upon by Board counsel are discussed in the above description of the position of the Applicant.

(c) Views of the Board

The Board agrees with the choice of 8-inch rather than 6-inch diameter pipe for the extension for the several reasons set forth in the submissions of the Applicant's witnesses.

The extension should provide ample capacity to meet the peak load of 371 Mcf/h forecast by the Applicant, with adequate security for firm customers on both the existing line and the extension.

The construction cost estimate of approximately $1.5 million for the project appears to the Board to be reasonable.

4. Right-of-Way Matters

(a) The Applicant's Position

When discussing the environmental aspects of the extension, Mr. Harper noted that there was only a small section of the project in the Town of Pembroke that will require a working easement and a permanent easement. The remainder of the route is in a road allowance, highway or railway right-of-way.

Mr. Harper noted that his environmental report assumed that, except for two instances, the proposed right-of-way did not go off road allowances or rights-of-way and that if portions of the extension varied from the proposed route, it would have to "be re-evaluated from an environmental point of view and additional guidelines and specifications would be applied to that project."

Mr. Harper undertook to notify the Ministry of the Environment of any such changes.

The routing of the extension in Pembroke makes it necessary to obtain easements from two private landowners - Storwal International Inc., and Pembroke Lumber Company Limited. Agreements to grant easement and right-of-way have been signed by the private landowners and were filed as Exhibits 20 and 21 respectively.

Mr. Girling testified with respect to the easements over private lands. He indicated that the proposed form of Grant of Easement was the Applicant's standard form that the Board had considered in previous proceedings, with one exception in that the proposed form grants the Applicant, in addition to the basic right-of-way, an easement over the grantor's lands abutting the easement lands. (Exhibit 22.) The Applicant undertook that it has offered or will offer the Grant of Easement to the private landowners affected by the current proceeding in the form of Exhibit 22.

(b) Submissions of Board Counsel

Board counsel cross-examined Mr. Girling with respect to the negotiations with the private landowners for the easements which they have agreed to grant to Consumers'.

(c) Views of the Board

The Board is concerned that pipeline easements should not, as a rule, require broad rights-of-way over the grantor's lands abutting the basic easements, such as the Applicant has included in Exhibit 22. However, this right over abutting lands was provided for in the agreements which were signed by the private landowners and filed as Exhibits 20 and 21. Therefore the Board is prepared to approve the inclusion of the right-of-way over the grantor's abutting lands, but only for the purposes of this proceeding.

The Board notes that the signed agreements refer to an easement for "a pipeline" whereas the form of Grant of Easement (Exhibit 22) refers to an easement for "pipelines". The leave to construct applied for in this proceeding relates to one specific pipeline and if, in the future, another transmission line is to be constructed, by looping or otherwise, a further application to the Board for leave to construct will be necessary. The Board will, in accordance with its past practice, require that the Grant of Easement be restricted to the purposes of one pipeline.

The Board, therefore, approves the form of Grant of Easement set out in Exhibit 22 to be offered to the private landowners, for the purpose of this proceeding, subject to the word "pipelines" in the penultimate line on page 2 of Exhibit 22 being struck out and replaced by the words "a pipeline".

The Board also approves the route for the extension selected by the Applicant.

5. Potential Sales from the Extension

(a) The Applicant's Position

The potential market to be served by the extension, as identified by the Applicant, falls into three distinct segments:

1. Conversions by users of other fuels located adjacent to the extension.
2. Residential and other units at CFB Petawawa to be served on a firm basis.
3. The central heating plant of CFB Petawawa to be served on an interruptible basis.

With respect to the first segment of the potential market the sales staff of the Applicant surveyed residential, commercial and industrial establishments along the extension. Mr. Houston testified with respect to the survey and the forecasted additions resulting from it. He suggested that his forecasted conversions may be pessimistic and that once it is known that a new pipeline is being installed additional persons might convert to natural gas. Mr. Houston, however, noted that the viability of the extension did not turn on the success in signing up new customers along the route of the extension.

> "Q. (Mr. Graholm): Do I gather from that that it's really an estimate because, perhaps, you didn't require to know the answers so precisely from these 100 customers because the project was already economic once you signed up the Forces?
>
> "A. (Mr. Houston): What happened, without going to Camp Petawawa, we certainly couldn't undertake to extend our lines along Highway from Pembroke to Petawawa to pick up the residential customers even if we got a hundred percent of them. It would not be feasible." (Transcript, pp. 117-118.)

Mr. Houston also indicated that the manager of a plaza and apartment blocks in the Village of Petawawa had shown an interest in using natural gas. (Exhibit 26.)

The Applicant's testimony was that the major loads to be served by the extension were the central heating plant, three schools and all 1,517 residential units at CFB Petawawa. Exhibit 23 was tendered as evidence of the Department of National Defence's intent in this matter. It is a letter dated April 20, 1979, from K. A. McLeod, Director General, Properties and Utilities at the Department of National Defence Headquarters in Ottawa to Mr. J. Graham at Ottawa Gas, a division of the Applicant.

In his letter, Mr. McLeod states that the Department intends to convert the central heating plant and up to one-third of the residential units prior to the start of the 1979-80 heating season and to complete the conversion of the other units within three years.

The residential units would be converted to burn natural gas for space heating and hot water. In the first year of conversions all gas consumed in these units would be billed directly to the Department of National Defence. Subsequently, all residential units would have individual meters installed and the individual users would be charged directly. The cost of the conversions, either by installation of a conversion burner or the replacement of the existing equipment with a new furnace, would be paid for by the Department of National Defence.

The cost to convert these units was estimated at $390 per conversion burner and $518 per new installation. Many of the residential units were said to require new installations.

The cost to convert the central heating plant was estimated to be $94,000 and would be paid for by the Department of National Defence. With this conversion the central heating plant would be capable of burning either heavy fuel oil (Bunker C) or natural gas.

The cost of the installation of meters would be borne by the Applicant.

(b) Submissions of Board Counsel

Board counsel in his cross-examination of Mr. Houston tested the economic incentive for a present user of heating oil, located in the vicinity of the extension, to convert to natural gas. Using the company's assumptions for average consumption for space heating purposes, and a price of $3.16 per Mcf in the first year of service, an average residential customer on the highway would save on a net basis in the neighbourhood of $35 or $32 per year over his previous heating costs after deducting the cost of the rental burner.

Some other issues touched upon earlier in this section were also raised by Board counsel.

(c) Views of the Board

The Board accepts that, if the extension is installed, its publicized presence may result in a greater volume of sales than was indicated in the Applicant's survey. The Board also notes that the Applicant's forecast for annual heating load for the residential units of CFB Petawawa was based on their historic consumption, adjusted for the different thermal efficiencies of the fuels and reduced by 5.5 percent. The 5.5 percent reduction in the first year was calculated to reflect that gas service would not be available in the first four months (May-August) of that year. This same percentage was then taken to be equal to the effect of conservation in the subsequent years. The Board thinks that this effort to predict the effect of conservation may be of limited value because little evidence was given as to the age and condition of the housing stock on the base, the extent of insulation and other aids to energy conservation, or the likely effect of converting from a system under which the Department of National Defence has purchased fuel for residential units to a system where individual tenants in the residential units would be directly responsible for their fuel costs.

As noted previously, the major market for natural gas to be served from the extension would be the central heating plant at CFB Petawawa. The gas would be sold under a Rate 140 interruptible contract. This form of service is fully interruptible at the Applicant's option for an unlimited number of days. However, the customer would be obligated to take and/or to pay for 75 percent of the agreed annual volume. The proposed term of contract under negotiation is one year. If, during the term of the contract, the cost of gas to be supplied increases, the customer would have the option of terminating the contract. This proposed contract will be discussed further in the subsequent parts of these Reasons for Decision.

The Board's assessment is that the Applicant's forecast of potential sales appears to be reasonable, but notes that it is highly dependent upon the assumptions as to the extent of the conversion to and of the continued use of natural gas at CFB Petawawa.

6. Economic Feasibility Matters

(a) The Applicant's Position

The Applicant's testimony on the question of economic feasibility was provided by Mr. Townsend, Consumers' Manager for its Eastern Region. He was assisted by Messrs. Walter Bruce Taylor, Director, Economic Evaluation and Statistics, and Fraser Dickson Rewbotham, Manager, Rate Research.

The Applicant used as a test of feasibility that the costs properly associated with additional facilities were not so onerous, when compared with a realistic level of revenues from those facilities, as to prevent the achievement of the rate of return permitted by the Board. The rate of return most recently determined by the Board as reasonable for Consumers' is 10.4 percent.

The Applicant's estimates of the costs that should be associated with the extension were probed at some length by Board counsel. The Applicant's approach was to estimate those costs assignable directly to the incremental facilities. For example, Consumers' calculated that the incremental operating cost for each residential customer was $41 per year for the purpose of the feasibility study. (Exhibit 9, Tab 9, p. 8.)

The basis for capital cost and construction cost estimates were those testified to by Mr. Graham in his direct testimony and the material that follows under Tab 5 of Exhibit 9.

A figure of one percent of the cost of the extension was used as an estimate for annual general taxes and a depreciation rate of 2.5 percent per year was used. In both cases the selected rates were somewhat higher than the rate levels calculated by the Applicant for the items.

These cost assumptions were then employed in the Applicant's economic feasibility model ("FEASO") which formed the quantitative basis for the Applicant's economic feasibility study.

The gas sales revenues employed by the Applicant in its economic feasibility study were derived from the estimates of the number of customers expected to be attached to the extension, their average consumption and assumed rates.

The estimates for average fuel usage for residential purposes at CFB Petawawa were based on the figures for the actual 1977-1978 oil usage for the months September 1 to April 30 inclusive. For the other uses, including the central heating plant, actual oil consumption on an historic basis was used. In the first year it was assumed gas would not be available until September 1, 1979. It was estimated that the full 12-month period requirement of 500,522 Mcf for the central heating plant would be reached in the third year. (Exhibit 29.)

The estimates of revenues from potential customers other than at CFB Petawawa were obtained by Mr. Townsend using the survey and other information testified to by Mr. Houston. Schedule 1 to Mr. Houston's direct testimony in Exhibit 9, Tab 4, sets out the forecasted additions. Another interruptible customer and his probable usage was forecast to be added in the third year of operation based on direct discussions with the potential customer. Fuel usage was estimated based on these surveys, direct interviews with potential customers, estimates of the average number of degree days and the Applicant's experience and judgment in the preparation of such forecasts.

The revenues derived from these sales were then calculated using FEASO. First the rates in effect on December 1, 1978, were employed in the model. A second FEASO run was done assuming that the rates proposed by the Applicant in an interim rate application in October, 1978, were in effect. Since that interim application was dismissed, the Board is not giving any weight to the second run. In Mr. Townsend's direct testimony he noted that, with the Applicant's assumptions for costs and revenues that were put into FEASO, the estimated return on rate base will reach a reasonable level of return in the third year.

Based on these calculations Mr. Townsend expressed the opinion that the project was economically feasible.

(b) Submissions of Board Counsel

Board counsel followed up on the quotation referred to in the discussion of Mr. Townsend's pre-filed direct testimony:

> "Q. I'm talking about after you did the Economic Feasibility Study, let's start from that point. You came up with these figures and then you made a decision as to whether you were going to go ahead with the project or not. I'm asking you whether anything else entered into the decision besides the numbers themselves?
>
> "A. No, other than the fact that we had approximately 94 per cent of the indicated gas load committed by Letter of Intent, which is a very nice load to have captured by Letter of Intent when you're looking at servicing a new area. It is certainly not the normal situation to have to crystal ball for the future, looking at 6 per cent and having 94 per cent already committed." (Transcript, p. 159.)

Board counsel, in cross-examination, challenged the reasonableness of some of the assumptions that went into the economic feasibility study. He tendered Exhibit 27 which was prepared by Board staff from data obtained from the Applicant in this or other proceedings and which adjusted some of the figures in Exhibit 9, Tab 6. Some of the items adjusted are discussed below.

Board counsel engaged in a discussion of the appropriate location for the measurement of degree day deficiency calculations. Mr. Townsend replied that Consumers' had made an additional FEASO run (Exhibit 29) as a result of a letter from Board counsel inquiring about this matter.

In addition to adjustments with respect to weather, Exhibit 29 also contained a revised assumption based on the Department of National Defence's plans to convert all of the residential water heaters within three years rather than eight years; the latter being the assumption used in the earlier runs of FEASO.

This revised economic feasibility study showed rates of return on estimated rate base for the third and fifth years of 12.16 and 12.34 percent respectively, rather than the rates of 11.25 and 11.92 percent shown in Exhibit 1 to Tab 6 of Exhibit 9, the initial FEASO run.

Another area of examination by Board counsel included the assumptions with respect to operations and maintenance ("O&M") expense. He asked Mr. Townsend, who was joined by Mr. Taylor, to explain the difference of $20 million between the estimates of the Applicant's total annual O&M expenses of $36 million used in this proceeding and the estimate of $56 million contained in Exhibit 28 in the Applicant's current rate case. In response to questioning Mr. Taylor confirmed that the estimate of O&M expense in the present proceeding did not include any expenses associated with exploration or development costs, natural gas production or gathering or other gas supply expenses. He also agreed that the expenses associated with underground storage and third party drilling costs, both of which are included in O&M expenses in the exhibit filed in the current rate proceeding, were excluded.

Mr. Taylor's justification for excluding these expenses from those to be allocated to the extension was that there would be no incremental expenses of this type "whether we add Petawawa or whether we don't".

Mr. Graholm continued this line of questioning with respect to excluding the exploration and development component of O&M expenses in an incremental cost study for testing feasibility. Mr. Rewbotham also joined in the interchange as set out below:

> "Q. All right. Now, why would you exclude the exploration and development?
>
> "A. Again, the addition of customers at Petawawa would not change our exploration program in any way and would not create an incremental operating expense in this area.
>
> "Q. Because you have ample supply available from the west, is that why?
>
> "A. We have an ample supply under contract, yes.

"Q. Well, you could use the same argument for any of your customers that you don't require your exploration for any of your customers, not just with the customers on the Petawawa line.

"A. The decision about whether we have an exploration program and a set of operating expenses for that exploration and production program is independent of this extension, that's what I am trying to say.

"Q. Yes.

"A. We would have a production program if we need that gas for our system as a whole and we wouldn't change it whether we have or have not got a Petawawa extension.

"Mr. MacOdrum: Mr. Taylor, once these customers are added into your system how are they different from any other customer within the Consumers' system?

"Mr. Taylor: They aren't any different.

"Mr. MacOdrum: So, why should the test of feasibility be different?

"Mr. Taylor: The test of feasibility isn't different. When any new customer is coming on we look at incremental costs, that's to my mind what you do in the feasibility study: you look at what additional costs, adding those new customers will create for the company and you look at what additional revenue you obtain from those customers.

"Mr. MacOdrum: Is that in part an exercise in allocation?

"Mr. Taylor: To me an allocation study is for other purposes such as pricing and not for feasibility.

"Mr. Rewbotham: I don't think, Mr. MacOdrum, we're looking at allocation in this sense, we're attempting to determine what are the incremental out-of-pocket costs that we would not bear if we did not add those customers versus what we will bear if we do increase the number of customers.

"Mr. MacOdrum: But we're getting to the point that I guess you're making is that this increment is so de minimis that you wouldn't incur any incremental supply related expenses to accomplish the additions either because of your own abundance of supply at this time or just because of good planning, good luck, or whatever, is that what you're telling us?

"A. We would incur the costs of purchasing gas from TransCanada PipeLines at a certain cost of cycling some of that gas through storage on an annual basis. And a certain amount of operating costs for those specific customers and those are then cash outlays, if you like, that we would expect to incur to match against the extra revenues that we can anticipate obtaining from those customers.

"Q. But the actual quantity compared to your total sales is so small that on the O & M side the operating -- the incremental operating costs are very small indeed, is that what you're --

"A. Yes, sir. And in addition new customers would likely have lower costs than older customers anyway." (Transcript, pp. 180-183.)

Board counsel also explored the treatment of marketing department costs and materials and contractor services as a component of O&M expense.

Mr. Townsend was asked why, although in the current rate proceeding approximately 20 percent of administrative and general costs were proposed to be capitalized as construction overheads, none of such costs were assigned to this proposed project. Mr. Townsend indicated that all such overheads for the Eastern Region were charged against expenses already budgeted and approved. It was admitted that "because of the internal procedures of Consumers' this particular project got a break as far as capitalization of overhead was concerned."

Mr. Taylor acknowledged, when examined, that interest during construction was not specifically capitalized with respect to this project as it was "a relatively small amount because of the very short construction period and we felt it would be easily absorbed in the contingency amount that Mr. Graham allowed of $100,000."

With respect to the exclusion of any allowance for gas in storage in the working capital allowance used in the feasibility study, Mr. Taylor said that Consumers' "felt that there was sufficient storage presently available to serve not only our existing customers but these additional customers and perhaps some other addition of customers without the purchasing of any incremental storage inventory."

In the context of an analysis of the recent decline in rates of return earned by the Applicant on new additions, Mr. Graholm also questioned the Applicant's rate of return targets used to establish economic feasibility.

Mr. Taylor explained that an 11 percent target rate of return was the rate used by the people in the Eastern Region and went on to state "my personal feeling is that I'm a lot more comfortable with about 11 1/2 and up because of the cost of new funds". However, Mr. Taylor would not agree with Board counsel that the actual incremental cost of capital is more than 12 percent.

In argument, Mr. Graholm referred to the statements of the Board in earlier decisions that existing customers should not be called upon to subsidize, through higher rates, new customers on extensions. He expressed concerns that the feasibility test did not truly relate costs and revenues on a comparable basis. For example, he indicated that for the present case an incremental O&M cost of $41 per customer was used, but that a much higher average system-wide cost of $99 was sought to be included in Consumers' rates in the current rate proceeding. In short, he felt that the $41 per customer figure employed in the economic feasibility study was probably understated.

He also repeated the concern he raised in cross-examination with respect to the exclusion of any allowance for the cost of storage in the working capital allowance.

Other matters raised in cross-examination by Board counsel which were outlined earlier in this section, were also dealt with in his concluding statement.

(c) Views of the Board

The Board accepts that on the test of economic feasibility employed by the Applicant and by the use of the Applicant's assumptions with respect to revenues and costs, the proposed project is economically feasible.

The Board accepts that the targets proposed by the Applicant for the rate of return on estimated rate base are reasonable.

The Board is concerned that, in determining the components of the "incremental" costs for the test of economic feasibility, the criterion of "out of pocket costs" may have been applied inconsistently.

The Board is not convinced by the arguments of the Applicant that the incremental operation and maintenance expense should include no allowance whatever for exploration and development, underground storage, third party exploration or other gas supply costs. These arguments appear to the Board to be valid only for small increments of new facilities over a short term and to disregard the cumulative effect of many such additions in increasing common costs with time. Similarly, the Board is concerned as to whether interest during construction and capitalization of construction overheads have been appropriately recognized.

In the opinion of the Board some more appropriate treatment of the items enumerated above might properly have been given in the cost of the project to assess its economic feasibility. For example, some allowance for the operation and maintenance items enumerated above might have been allocated to the incremental cost of the project. The Board has not made such an allocation because, to be consistent, it would also have had to make offsetting adjustments to make the cost of gas properly incremental. The Board is aware that, as Board counsel noted, the Applicant on a system-wide basis, is faced with potential costs in the form of unabsorbed demand charges as a consequence of an imbalance between forecasted demand and contracted supply. The potential savings from the extension in reducing these unabsorbed demand charges may have been taken into consideration when the Applicant assessed the economic feasibility of and the risks associated with the extension. If these offsetting adjustments were considered by the Applicant, the Board believes that the project may properly have been viewed as a more attractive undertaking. The Board, however, does not carry this speculation any further. Such a consideration and how it relates to the question of the "prudency of cost incurrence by utility management" is an issue that lies at the heart of each rate proceeding of the Applicant.

The Board's fundamental area of concern, in the matter of economic feasibility, is one it shares with the Applicant.

Mr. Townsend noted that there was a "Federal policy in Canada which is favouring the use of gas as much as possible". He went on to note that there was interest in increasing large volume industrial contracts in the Eastern Region. He said:

> "We have one very large customer we are negotiating with and he-it wants to talk long

term contract. This is a customer which is several times larger than we're talking about here in volume and if he's willing to talk multi-year contract then we become less concerned about the possibility of the Forces Base reverting back to oil on a full time basis.

"Mr. MacOdrum: You mean a long term customer adjacent to the Pembroke-Petawawa?

"Mr. Townsend: No, no, just long term customer in the vicinity of Ottawa.

"Mr. MacOdrum: So, it's not a concern --

"Mr. Townsend: It's not germane to this line of this discussion today except for the fact that it does indicate that long term number 6 oil Bunker C customers or number 6, not long term, are looking towards long term natural gas contracts. So, we have less concern about the possibility of losing this contract.
"Mr. Graholm: Q. So, you are concerned about the Department of National Defence then going back to Bunker C?

"(Answers by Mr. Townsend)

"A. We are concerned about them going back.

"Q. Yes.

"A. I have no serious concern on the matter, no. If I felt that that was a serious risk we would not have come forward today.

"Q. Who made the decision in Consumers' to accept this risk?

"A. The decision to proceed with this feasibility was mine presented to the Vice-President of Operations of the Company Mr. R. W. Martin who in turn would have presented it to the meeting of the Vice-Presidents. Following that, the decision was taken to approve the capital expenditures involved, subject to the Board's approval of course." (Transcript, pp. 124-126.)

Thus it seems clear that the Applicant at a senior management level is prepared to assume the risks arising from the construction of the extension.

An analysis of these risks is in order. In the fifth year of operation, 520,992 Mcf of total sales of 791,744 Mcf would be sold under large volume interruptible contracts. In that year, 500,522 Mcf (over 60 percent of total sales from the extension) would be sales to the central heating plant at CFB Petawawa. (Exhibit 29.) This central heating plant has and would continue to have the capability of burning Bunker C fuel oil after its conversion to burn natural gas.

The contract that Consumers' has proposed to the Department of National Defence is for a one-year term. Although the purchaser would be obligated to take and/or pay for 75 percent of the agreed annual volume, if the cost of the gas sold under the contract were to be increased, the purchaser would have the option of terminating the contract. As Mr. Townsend agreed, it is inherent, in a judgment that the proposal is feasible, that a price advantage, over the existing Bunker C cost, remain for several years into the future. Such a price advantage currently prevails under the pricing provisions of the contract offered by Consumers' to the Department of National Defence.

He acknowledged, in indicating that Consumers' is not looking for industrial contracts for longer than one year, that a reason was "the flexibility of the market situation". He went on to note "it's just a very volatile market".

The Board concludes that the Applicant, a long-established and responsible utility with an experienced management, has made the judgment that it would bear the risks in full awareness of the market conditions described by Mr. Townsend.

The Board observes that there are at least two ways in which these risks could be minimized. One was raised by Mr. Graholm who suggested that the Applicant could negotiate a grant in aid of construction of the extension with the Department of National Defence in view of the fact that over 94 percent of the total forecast load would go to meet the Department's needs.

Another alternative available to the Applicant would be to seek a contract with a term longer than one year and without an option to the purchaser to terminate in the event of any gas cost escalation. The purchaser would remain obligated to pay for some portion of the contracted quantity of gas, even if it did not want it and even if the gas cost increased. Several variations in the exact details of the gas cost escalation provisions could be made. For example, the purchaser could retain the right to terminate if the gas cost escalated at a rate higher than a stated percentage or beyond a stated amount. The negotiators for both the Applicant and prospective purchasers would no doubt have the ingenuity to draft the precise language of such provisions.

The Board does not claim any originality in this concept. Mr. Houston noted that contracts longer than one year had previously been entered into by Consumers' and Mr. Townsend, in the quotation referred to earlier, noted that a new customer in Ottawa was seeking a contract for a term longer than one year.

It was also established that Consumers' changed to the "one year contract" policy as a "restriction put on us by the supply situation of a few years ago" and it was acknowledged that the supply situation that necessitated this policy had changed in a significant way when Mr. Houston went on to note "yes, the supply has improved, yes, certainly".

The Board is aware and can take administrative notice of the February 1979 report of the National Energy Board "Canadian Natural Gas Supply and Requirements" which details the basis for a much improved supply situation with respect to Canadian natural gas than that described, for instance, in the National Energy Board's 1975 report on the same subject.

Mr. Houston, when asked whether the company has given any thought to changing its policy of not seeking longer term contracts, indicated affirmatively. However, later in the hearing Mr. Atkinson reported on a telephone discussion he had on the subject with Mr. Potts, the Manager of Commercial and Industrial Sales for the company and the person in overall charge of contracts.

Mr. Atkinson reported that there is no policy to stop Consumers' from signing a large volume contract for more than one year. However, he said that Mr. Potts could not remember any customer who asked for a contract in excess of one year or for that matter who was prepared to sign one. Mr. Potts was also reported to have advised that "he cannot see an instance where any customer would sign a contract where the increase clause was removed". The increase clause is the clause which allows the customer to cancel the contract in the event of an increase in gas costs.

In view of the fact that Mr. Atkinson's report of the discussion was not evidence presented by the Applicant in a manner which would lend itself to cross-examination, the Board cannot attach to it the same weight as that of the other evidence that was so tested.

The Board notes that Mr. Townsend when asked: "so what happens to the $1 1/2 million you spent on the pipeline if you lose this customer in a few years?" commented on the basis for his view of the feasibility of the project.

> "Mr. Townsend: A. I think, we're going on past practice and we're going on the Canadian position for energy in Canada and certainly we have a Federal policy in Canada which is favouring the use of natural gas as much as possible . . . ." (Transcript, p. 124.)

Mr. Atkinson in his argument also referred to the Federal policy to favour the use of natural gas.

The proposed purchaser of the natural gas upon which the feasibility of this extension depends is the Department of National Defence, a department of the Federal Government. The Applicant is relying largely on a letter of intent from that Department, although Mr. Townsend said that he expected to have the gas sales contract signed before construction starts. A more certain manifestation of the Federal policy in this regard would be the commitment to gas of the central heating plant load at CFB Petawawa, for a term longer than one year with take-or-pay or other cost penalty provisions. The entering into of such a contract in the current case would reduce the risk which the Applicant would assume with the construction of the extension.

With respect to the residential units at CFB Petawawa, the Board understands that the Applicant may receive revenue from the Department of National Defence for the installation of new furnaces and conversion burners. The early firming up of such an arrangement would also reduce the Applicant's exposure to the risks arising from the project.

7. Disposition of the Application

Having considered the evidence and in the light of the views expressed earlier herein, the Board is of the opinion, subject to the conditions set out below, that the construction of the extension by the Applicant is in the public interest and an order granting leave to construct will be issued.

The Board is further of the opinion that the construction should be undertaken and completed within a reasonable time of an order granting such leave.

The order granting leave to construct shall include conditions to provide that:

1. The proposed pipeline and facilities shall be constructed in accordance with:

   i) the Contract Specifications - Main and Service Construction 1978; (Exhibit 13.)

   ii) Construction drawings for 8-inch Petawawa Pipeline Project. (Exhibit 11A.)

2. The Applicant shall comply with all the undertakings given by its witnesses and counsel during the course of the current proceeding, but subject to the fourth condition set out below.

3. The Applicant shall notify the Board forthwith upon the completion of construction of the extension and the leave to construct granted by the order shall terminate on December 31, 1980,

unless the construction of the extension has been completed by that date.

4. The Applicant will offer to each private landowner a grant of easement agreement in the form set out in Exhibit 22, amended as provided for earlier herein.

The Board has expressed its concern about the risks arising from the Applicant's proposal to proceed on the basis of the letter of intent from the Department of National Defence and a one-year contract with an option to terminate in the event of any gas cost escalation. It may well be that the risks of proceeding on that basis should not necessarily be borne entirely by the customers. Therefore, the Board considers it important to note that the granting of leave to construct the extension is not a determination of the treatment to be given to the costs of such facilities in subsequent rate proceedings of the Applicant. In such proceedings the prudency of management in incurring costs to provide utility service is subject to extensive review.

8. Costs

The Board's costs will be charged to the Applicant in accordance with the Board's usual practice.

9. <u>Order</u>

The Board requires the Applicant to draft and submit to the Board an appropriate order in accordance with these Reasons for Decision.

DATED at Toronto this 5th day of June, 1979.

ONTARIO ENERGY BOARD

J. R. Dunn
Presiding Member

D. M. Treadgold
Member

I. Bruce MacOdrum

I. B. MacOdrum
Member