EB-2009-0172

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 Enbridge Gas Distribution Inc. 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 January 1, 2010.

BOARD STAFF COMPENDIUM FOR PRELIMINARY MOTION
NOVEMBER 24, 2009

EB-2009-0172

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 Enbridge Gas Distribution Inc. 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 January 1, 2010.

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NOVEMBER 24, 2009

INDEX

EB-2009-0172

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

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BOARD STAFF COMPENDIUM FOR PRELIMINARY MOTION
NOVEMBER 24, 2009

1. Undertaking Given by Enbridge Gas Distribution Inc. on December 7, 1999 and effective March 31, 1999
2. Minister's Directive August 10, 2006
3. Minister's Directive September 8, 2009
4. Green Energy Initiatives, Enbridge Application, Exhibit B, Tab 2, Schedule 4 plus Appendices
5. *Ontario Energy Board Act, 1998*, S.O 1998, c.15, (Schedule B), sections 2(1), 27.1, 36(2), and 78(3)
6. Union Gas Ltd. V. Ontario (Energy Board), [1983] O.J. 3191 (S.C.)
7. Advocacy Centre for Tenant-Ontario v. Ontario Energy Board, [2008] O.J. 1970 (Div. Ct.)
8. ATCO Gas and Pipelines Ltd. V. Alberta (Energy and Utilities Board), [2006] 1 S.C.R. 140
9. *Guidelines: Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities*, G-2009-0300, September 15, 2009
10. EBO 179-14/15, March 31, 1999
11. *Generic DSM Decision*, EB-2006-0021, August 25, 2006

TAB 1

UNDERTAKINGS OF THE CONSUMERS' GAS COMPANY LTD., ENBRIDGE CONSUMERS ENERGY INC., 311594 ALBERTA LTD., ENBRIDGE PIPELINES (NW) INC. AND ENBRIDGE INC.

TO: Her Honour The Lieutenant Governor in Council for the Province of Ontario

WHEREAS Enbridge Consumers Energy Inc. holds all of the issued and outstanding common shares of The Consumers' Gas Company Ltd. ("Consumers");

AND WHEREAS 311594 Alberta Ltd. holds all of the issued and outstanding common shares of Enbridge Consumers Energy Inc.;

AND WHEREAS Enbridge Pipelines (NW) Inc. holds all of the issued and outstanding common shares of 311594 Alberta Ltd.;

AND WHEREAS Enbridge Inc. ("Enbridge") holds all of the issued and outstanding common shares of Enbridge Pipelines (NW) Inc.;

the above named corporations do hereby agree to the following undertakings:

1.0 Definitions

In these undertakings,

1.1 "Act" means the *Ontario Energy Board Act, 1998*;

1.2 **"affiliate"** has the same meaning as it does in the *Business Corporations Act*;

1.3 **"Board"** means the Ontario Energy Board;

1.4 **"business activity"** has the same meaning as it does under the Act or a regulation made under the Act; and

1.5 **"electronic hearing"**, **"oral hearing"** and **"written hearing"** have the same meaning as they do under the *Statutory Powers Procedure Act*.

2.0 Restriction on Business Activities

2.1 Consumers shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.

3.0 Maintenance of common equity

3.1 Where the level of equity in Consumers falls below the level which the Board has determined to be appropriate in a proceeding under the Act or a predecessor Act, Consumers shall raise or Enbridge and its affiliates shall provide within 90 days, or such longer period as the Board may specify, sufficient additional equity capital to restore the level of equity in Consumers to the appropriate level.

3.2 Any additional equity capital provided to Consumers by Enbridge or its affiliates shall be provided on terms no less favourable to Consumers than Consumers could obtain directly in the capital markets.

4.0 Head Office

4.1 The head office of Consumers shall remain within the franchise area of Consumers.

5.0 Prior Undertakings

5.1 Subject to Article 5.2, these undertakings supersede, replace and are in substitution for all prior undertakings of Consumers, Enbridge and their affiliates.

5.2 The undertakings of British Gas PLC and Consumers dated June 16th, 1994 and approved by the Lieutenant Governor in Council on June 23rd, 1994, remain in full force and effect.

6.0 Dispensation

6.1 The Board may dispense, in whole or in part, with future compliance by any of the signatories hereto with any obligation contained in an undertaking.

7.0 Hearing

7.1 In determining whether to grant an approval under these undertakings or a dispensation under Article 6.1, the Board may proceed without a hearing or by way of an oral, written or electronic hearing.

8.0 Monitoring

8.1 At the request of the Board, Consumers, Enbridge and their affiliates will provide to the Board any information the Board may require related to compliance with these undertakings.

9.0 Enforcement

9.1 The parties hereto acknowledge that there has been consideration exchanged for the receipt and giving of the undertakings and agree to be bound by these undertakings.

9.2 Any proceeding or proceedings to enforce these undertakings may be brought and enforced in the courts of the Province of Ontario and Enbridge, Consumers and their affiliates hereby submit to the jurisdiction of the courts of the Province of Ontario in respect of any such proceeding.

9.3 For the purpose of service of any document commencing a proceeding in accordance with Article 9.2, it is agreed that Consumers is the agent of Enbridge and its affiliates and that personal service of documents on Consumers will be sufficient to constitute personal service on Enbridge and its affiliates.

10.0 Release from undertakings

10.1 Enbridge, Consumers and their affiliates are released from these undertakings on the day that Enbridge no longer holds, either directly or through its affiliates, more than 50 per cent of the voting securities of Consumers or on the day that Consumers sells its gas transmission and gas distribution systems.

11.0 Effective Date

11.1 These undertakings become effective on March 31, 1999.

DATED this 7th day of December, 1998.

THE CONSUMERS' GAS COMPANY LIMITED

by ______________________

____

ENBRIDGE CONSUMERS ENERGY INC.

by ______________________

____

311594 ALBERTA LTD.

by ______________________

____

ENBRIDGE PIPELINES (NW) INC.

by ______________________

____

ENBRIDGE INC.

by ______________________

____

TAB 2

Ontario
Executive Council
Conseil des ministres

Order In Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le con- sentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999; and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998, and that took effect on March 31, 1999;

AND WHEREAS opportunities exist for Enbridge Distribution Inc. and Union Gas Limited to carry on business activities that could assist the Government of Ontario in achieving its goals in energy conservation;

AND WHEREAS the Minister of Energy may issue, and the Ontario Energy Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources;

NOW THEREFORE the attached Directive is approved.

Recommended: ______________________
Minister of Energy

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: AUG 10 2006
Date

____
Administrator of the Government

O.C./Décret 1537/2006

Minister of Energy

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Fax: 416-327-6574

Ministre de l'Énergie

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Ontario

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and

- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation, including services related to:

(a) the promotion of electricity conservation, natural gas conservation and the efficient use of electricity;

(b) electricity load management; and

(c) the promotion of cleaner energy sources, including alternative energy sources and renewable energy sources.

.../cont'd

In addition, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Enbridge Undertakings, with future compliance with section 2.1 of the Enbridge Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the local distribution of steam, hot and cold water in a Markham District Energy initiative; and

(b) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

Further, pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, I hereby direct the Board to dispense, under section 6.1 of the Union Undertakings, with future compliance with section 2.1 of the Union Undertakings in respect of research, review, preliminary investigation, project development and the provision of services related to the following business activities:

(a) the generation of electricity by means of large stationary fuel cells integrated with energy recovery from natural gas transmission and distribution pipelines.

To the extent that any activities undertaken by Enbridge Gas Distribution Limited or Union Gas Limited in reliance on this Directive are forecast to impact upon their regulated rates, such activities are subject to the review of the Ontario Energy Board under the *Ontario Energy Board Act, 1998*.

In this directive, "alternative energy source" and "renewable energy source" have the same meanings as in the *Electricity Act, 1998*.

Dwight Duncan
Minister

TAB 3

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Gas Distribution Inc. and related parties ("Enbridge") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"), and Union Gas Limited and related parties ("Union") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings");

AND WHEREAS the Minister of Energy and Infrastructure has the authority under section 27.1 of the *Ontario Energy Board Act, 1998* to issue directives, approved by the Lieutenant Governor in Council, that require the Ontario Energy Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management and the use of cleaner energy sources including alternative and renewable energy sources;

AND WHEREAS The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009,* embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario;

AND WHEREAS certain amendments to the *Ontario Energy Board Act, 1998* provided for by the above-noted statute authorize electricity distribution companies to directly own and operate renewable energy electricity generation facilities with a capacity of ten (10) megawatts or less, facilities that generate heat and electricity from a single source, or facilities that store energy, subject to criteria to be prescribed by regulation;

AND WHEREAS it is desirable that both Enbridge and Union are accorded authority similar to those of electricity distributors to own and operate the kinds of generation and storage facilities referenced above, while clarifying that the latter two activities, namely the ownership and operation of facilities that generate heat and electricity from a single source, or facilities that store energy, are to be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity, as well as to allow Enbridge and Union the authority to own and operate assets required in respect of the provision of services by Enbridge and Union that would assist the Government of Ontario in achieving its goals in energy conservation including where such assets relate to solar-thermal water and ground-source heat pumps;

AND WHEREAS the Minister of Energy has previously issued a directive pursuant to section 27.1 in respect of the Enbridge Undertakings and the Union Undertakings, under Order-in-Council No. 1537/2006, dated August 10, 2006.

NOW THEREFORE the directive attached hereto is approved and is effective as of the date hereof.

Recommended: ______________________
Minister of Energy and Infrastructure

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: SEP 0 8 2009
Date

____
Lieutenant Governor

O.C./Décret 1540/2009

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings Relating to the Ownership and Operation of Renewable Energy Electricity Generation Facilities, Facilities Which Generate Both Heat and Electricity From a Single Source and Energy Storage Facilities and the Ownership and Operation of Assets Required to Provide Conservation Services.

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009,* embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario.

One of those initiatives is to allow electric distribution companies to directly own and operate renewable energy electricity generation facilities of a capacity of not more than 10 megawatts or such other capacity as is prescribed by regulation, facilities which generate both heat and electricity from a single source and facilities for the storage of energy, subject to such further criteria as may be prescribed by regulation.

The Government also wants to encourage initiatives that will reduce the use of natural gas and electricity.

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, and in addition to a previous directive issued thereunder on August 10, 2006 by Order in Council No. 1537/2006, in respect of the Enbridge Undertakings and the Union Undertakings, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and

- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the ownership and operation by Enbridge Gas Distribution, Inc. and Union Gas Limited, of:

(a) renewable energy electricity generation facilities each of which does not exceed 10 megawatts or such other capacity as may be prescribed, from time to time, by regulation made under clause 71(3)(a) of the *Ontario Energy Board Act, 1998* and which meet the criteria prescribed by such regulation;

(b) generation facilities that use technology that produces power and thermal energy from a single source which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(b) of the *Ontario Energy Board Act, 1998*;

(c) energy storage facilities which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(c) of the *Ontario Energy Board Act, 1998*; or

(d) assets required in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation and includes assets related to solar-thermal water and ground-source heat pumps;

(e) for greater certainty, the use of the word "facilities" in paragraphs (b) and (c) above shall be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity.

This directive is not in any way intended to direct the manner in which the Ontario Energy Board determines, under the *Ontario Energy Board Act, 1998,* rates for the sale, transmission, distribution and storage of natural gas by Enbridge Gas Distribution Inc. and Union Gas Limited.

George Smitherman

George Smitherman
Deputy Premier, Minister of Energy and Infrastructure

TAB 4

GREEN ENERGY INITIATIVES: Y-FACTOR REQUEST

1. In order to assist in meeting the Ontario Government's clean energy objectives, and to meet the evolving energy needs of its customers, the Company plans to pursue initiatives and own and operate a variety of assets capable of generating and distributing alternative forms of energy to end-use customers in Enbridge's franchise areas. Through these initiatives, Enbridge would design, market, invest in, own and operate assets that will primarily focus on providing space heating and cooling and domestic hot water for its customers. Some examples of the alternate and renewable energy solutions that Enbridge plans to offer include solar, ground source heat pumps, distributed and District Energy systems, micro combined heat and power ("CHP") and heat from waste technologies, geo-thermal systems and stationary fuel cell facilities (referred to in this evidence as "Green Energy Initiatives").

2. A recent Minister's Directive, issued September 8, 2009, permits the Company to undertake Green Energy Initiatives within the utility. It is clear from the Minister's Directive that such projects and the associated costs, assets and revenues may be included as part of Enbridge's regulated operations, subject of course to review and approval by the Board. A copy of the Minister's Directive is attached as Exhibit B, Tab 2, Schedule 4, Appendix A.

3. Enbridge has a number of potential Green Energy Initiatives that it plans to undertake in 2010. The Company therefore requests the establishment of a 2010 Y-factor (in the amount of approximately $300,000 of revenue requirement) to allow the recovery in rates of costs related to these projects. In accordance with the IRM Settlement Agreement, Enbridge also requires and requests the Board's approval to undertake Green Energy Initiatives as "new regulated energy services".

Witnesses: P. Hoey
S. Kancharla

(a) The Ontario Government's Clean Energy Objectives

4. The Ontario Government's goals of promoting conservation and the use of cleaner energy sources are well known. The Ontario Government has established targets for CO^2 reduction of 18% by 2014, 26% by 2020 and 83% by 2050, all from a baseline of 2004 actual greenhouse gas ("GHG") emissions in Ontario.

5. Through measures such as the recent *Green Energy and Green Economy Act, 2009*, the Ontario Government has signalled that the responsibility for delivering the anticipated benefits of a "greener future" lies in large part with existing regulated market players.

6. The evolution towards a significant role for renewable energy in Ontario is not simply about electricity production. Ontario's thermal energy requirements also contribute substantially to total GHG emissions.

7. Enbridge's offerings of Green Energy Initiatives would contribute towards meeting many of the Province's ambitious clean energy goals, including reductions in energy waste, distribution losses and GHG emissions. Other benefits include the improvements that will accrue to system reliability as well as contributions to sustainable communities.

(b) Enbridge's Role in Green Energy Initiatives

8. Despite apparent market appetite, Green Energy Initiatives are not proceeding with the required frequency in Ontario to meet GHG reduction targets.

9. Enbridge is well-positioned to assist the Ontario Government, and interested energy consumers, by delivering Green Energy Initiatives. The Company has unparalleled experience in the delivery of energy to Ontario consumers, and has strong relationships with many industry partners and potential customers for these new

services. Enbridge can offer these potential customers the credibility and stability needed to support their decisions to commit to use emerging and new Green Energy Initiatives.

10. Enbridge's existing customers can also benefit from these new activities. Examples of these benefits are the addition of sustainable and growing business opportunities that will provide new sources of revenue to contribute towards Enbridge's long-term sustainability and the availability of different options for customers.

11. The Ontario Government has recognized the role that Enbridge can play in the provision of Green Energy Initiatives through the issuance of Minister's Directives in August 2006 and September 2009. These Directives authorize Enbridge (and Union Gas Limited) to own and operate renewable generation facilities and to own assets and provide services that assist the Ontario Government in meeting its energy conservation goals.

(c) Enbridge's Near-Term Green Energy Initiatives

12. Distributed energy projects represent an example of Green Energy Initiatives that the Company could design, build and operate within the utility in the near term. They are a logical extension of Enbridge's core service and complement its core competencies in a number of different areas.

13. These projects have high initial capital costs, but they also have a long lifespan, with a steady stream of revenue over that time. Like many utility assets, there is a relatively long pay-back period associated with these projects. In addition, as is the case with natural gas system expansions, associated costs exceed revenues in the early years of the project, while revenues exceed costs in later years, This means

that, in order for the projects to be viable, they must be treated in the same way as Enbridge's other regulated activities.

14. The Company has been approached by and met with a number of parties about potential Green Energy Initiatives in its franchise area. The applications range from multi residential projects to small industrial projects to single family home projects. Each project has a different timeline and cost and revenue structure. Some projects are new construction projects, while others are retrofit projects.

15. With OEB approval of Enbridge's request to serve these customers as part of the regulated utility, the Company would enter into contract negotiations with a number of the parties and commence construction in 2010 with completion of some projects prior to the end of 2010. The total cost of the Green Energy Initiatives that Enbridge plans to pursue in 2010 is approximately $10 million, of which $4.0 million is forecast to be closed to rate base in 2010. This results in an associated 2010 revenue requirement of approximately $300,000.

(d) Regulatory Treatment

16. Enbridge proposes that Green Energy Project assets would be included in the regulated utility and would be a component of total rate base for ratemaking purposes. Operating costs and revenues associated with these projects would be included when calculating the utility revenue requirement and any deficiency/sufficiency for ratemaking purposes. At this time, Enbridge expects that the amounts to be charged to customers connecting to these projects would be set by contract. As a result, it will not be necessary for the OEB to establish rates for these customers.

Witnesses: P. Hoey
S. Kancharla

17. Enbridge's approach to the evaluation and choice of system expansion projects will evolve to incorporate Green Energy Initiatives, in addition to natural gas projects. Enbridge will ensure that the combined impact of all 2010 expansion projects will result in a positive net present value.

18. In the ordinary course (non-IRM), the assets associated with the Green Energy Initiatives would become part of Enbridge's rate base, along with the O&M costs and the revenues associated with the projects on an annual basis. At this time, in the middle of IRM, the process is somewhat different. Enbridge therefore requests instead that a Y-factor be established to allow the Company to recover the deficiency associated with the Green Energy Initiatives in 2010.

(d) Approvals Requested

19. First, Enbridge seeks the Board's approval, pursuant to Issue 12.2 of the IRM Settlement Proposal, to offer Green Energy Initiatives as new regulated energy services.

20. Second, Enbridge requests the establishment of a 2010 Y-factor related to Green Energy Initiatives. For 2010, the impact from anticipated Green Energy Initiatives is approximately $300,000 in revenue requirement (See Exhibit B, Tab 2, Schedule 4, Appendix B). The 2010 Y-factor would be adjusted the following year, based on actual costs.

Witnesses: P. Hoey
S. Kancharla

Ontario
Executive Council
Conseil des ministres

Order in Council
Décret

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and concurrence of the Executive Council, orders that:

Sur la recommandation du soussigné, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil des ministres, décrète ce qui suit:

WHEREAS Enbridge Gas Distribution Inc. and related parties ("Enbridge") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"), and Union Gas Limited and related parties ("Union") gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings");

AND WHEREAS the Minister of Energy and Infrastructure has the authority under section 27.1 of the *Ontario Energy Board Act, 1998* to issue directives, approved by the Lieutenant Governor in Council, that require the Ontario Energy Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management and the use of cleaner energy sources including alternative and renewable energy sources;

AND WHEREAS The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009*, embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario;

AND WHEREAS certain amendments to the *Ontario Energy Board Act, 1998* provided for by the above-noted statute authorize electricity distribution companies to directly own and operate renewable energy electricity generation facilities with a capacity of ten (10) megawatts or less, facilities that generate heat and electricity from a single source, or facilities that store energy, subject to criteria to be prescribed by regulation;

AND WHEREAS it is desirable that both Enbridge and Union are accorded authority similar to those of electricity distributors to own and operate the kinds of generation and storage facilities referenced above, while clarifying that the latter two activities, namely the ownership and operation of facilities that generate heat and electricity from a single source, or facilities that store energy, are to be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity, as well as to allow Enbridge and Union the authority to own and operate assets required in respect of the provision of services by Enbridge and Union that would assist the Government of Ontario in achieving its goals in energy conservation including where such assets relate to solar-thermal water and ground-source heat pumps;

AND WHEREAS the Minister of Energy has previously issued a directive pursuant to section 27.1 in respect of the Enbridge Undertakings and the Union Undertakings, under Order-in-Council No. 1537/2006, dated August 10, 2006.

NOW THEREFORE the directive attached hereto is approved and is effective as of the date hereof.

Recommended: ______________________
Minister of Energy and Infrastructure

Concurred: ______________________
Chair of Cabinet

Approved and Ordered: SEP 0 8 2009
Date

____
Lieutenant Governor

O.C./Décret 1540/2009

MINISTER'S DIRECTIVE

Re: Gas Utility Undertakings Relating to the Ownership and Operation of Renewable Energy Electricity Generation Facilities, Facilities Which Generate Both Heat and Electricity From a Single Source and Energy Storage Facilities and the Ownership and Operation of Assets Required to Provide Conservation Services.

Enbridge Gas Distribution Inc. and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Enbridge Undertakings"); and Union Gas Limited and related parties gave undertakings to the Lieutenant Governor in Council that were approved by Order in Council on December 9, 1998 and that took effect on March 31, 1999 ("the Union Undertakings").

The Government of Ontario has, with the passage of the *Green Energy and Green Economy Act, 2009,* embarked upon a historic series of initiatives related to promoting the use of renewable energy sources and enhancing conservation throughout Ontario.

One of those initiatives is to allow electric distribution companies to directly own and operate renewable energy electricity generation facilities of a capacity of not more than 10 megawatts or such other capacity as is prescribed by regulation, facilities which generate both heat and electricity from a single source and facilities for the storage of energy, subject to such further criteria as may be prescribed by regulation.

The Government also wants to encourage initiatives that will reduce the use of natural gas and electricity.

Pursuant to section 27.1 of the *Ontario Energy Board Act, 1998*, and in addition to a previous directive issued thereunder on August 10, 2006 by Order in Council No. 1537/2006, in respect of the Enbridge Undertakings and the Union Undertakings, I hereby direct the Ontario Energy Board to dispense,

- under section 6.1 of the Enbridge Undertakings, with future compliance by Enbridge Gas Distribution Inc. with section 2.1 ("Restriction on Business Activities") of the Enbridge Undertakings, and
- under section 6.1 of the Union Undertakings, with future compliance by Union Gas Limited with section 2.1 ("Restriction on Business Activities") of the Union Undertakings,

in respect of the ownership and operation by Enbridge Gas Distribution, Inc. and Union Gas Limited, of:

(a) renewable energy electricity generation facilities each of which does not exceed 10 megawatts or such other capacity as may be prescribed, from time to time, by regulation made under clause 71(3)(a) of the *Ontario Energy Board Act, 1998* and which meet the criteria prescribed by such regulation;

(b) generation facilities that use technology that produces power and thermal energy from a single source which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(b) of the *Ontario Energy Board Act, 1998*;

(c) energy storage facilities which meet the criteria prescribed, from time to time, by regulation made under clause 71(3)(c) of the *Ontario Energy Board Act, 1998*; or

(d) assets required in respect of the provision of services by Enbridge Gas Distribution Inc. and Union Gas Limited that would assist the Government of Ontario in achieving its goals in energy conservation and includes assets related to solar-thermal water and ground-source heat pumps;

(e) for greater certainty, the use of the word "facilities" in paragraphs (b) and (c) above shall be interpreted to include stationary fuel-cell facilities each of which does not exceed 10 Megawatts in capacity.

This directive is not in any way intended to direct the manner in which the Ontario Energy Board determines, under the *Ontario Energy Board Act, 1998,* rates for the sale, transmission, distribution and storage of natural gas by Enbridge Gas Distribution Inc. and Union Gas Limited.

George Smitherman

George Smitherman
Deputy Premier, Minister of Energy and Infrastructure

CAPITAL STRUCTURE
GREEN ENERGY INITIATIVES

Line No.		Col. 1 Component %	Col. 2 Indicated Cost Rate %	Col. 3 Return Component %
1.	Long-term debt	64.00	6.38	4.08
2.	Short-term debt	-	-	-
3.		64.00		4.08
4.	Preference shares	-	-	-
5.	Common equity	36.00	8.31	2.99
6.		100.00		7.07

	($000's)	2010
7.	Ontario Utility Income	(56.8)
8.	Rate base	2,145.1
9.	Indicated rate of return	(2.65)%
10.	(Def.) / suff. in rate of return	(9.72)%
11.	Net (def.) / suff.	(208.5)
12.	Gross (def.) / suff.	(306.6)

RATE BASE
GREEN ENERGY INITIATIVES

($000's)

Line No.		2010
	Property, plant, and equipment	
1.	Cost or redetermined value	2,169.0
2.	Accumulated depreciation	(23.9)
3.		2,145.1
	Allowance for working capital	
4.	Accounts receivable merchandise finance plan	-
5.	Accounts receivable rebillable projects	-
6.	Materials and supplies	-
7.	Mortgages receivable	-
8.	Customer security deposits	-
9.	Prepaid expenses	-
10.	Gas in storage	-
11.	Working cash allowance	-
12.		-
13.	Ontario utility rate base	2,145.1

INCOME
GREEN ENERGY INITIATIVES

($000's)

Line No.		2010
	Revenue	
1.	Gas sales	-
2.	Transportation of gas	-
3.	Transmission and compression	-
4.	Other operating revenue	-
5.	Other income	-
6.	Total revenue	-
	Costs and expenses	
7.	Gas costs	-
8.	Operation and Maintenance	-
9.	Depreciation and amortization	95.4
10.	Municipal and other taxes	29.4
11.	Total costs and expenses	124.8
12.	**Utility income before inc. taxes**	(124.8)
	Income taxes	
13.	Excluding interest shield	(40.0)
14.	Tax shield on interest expense	(28.0)
15.	Total income taxes	(68.0)
16.	**Ontario utility net income**	(56.8)

TAXABLE INCOME AND INCOME TAX EXPENSE
GREEN ENERGY INITIATIVES

($000's)

Line No.		2010
1.	Utility income before income taxes	(124.8)
	Add Backs	
2.	Depreciation and amortization	95.4
3.	Large corporation tax	-
4.	Other non-deductible items	-
5.	Any other add back(s)	-
6.	Total added back	95.4
7.	Sub total - pre-tax income plus add backs	(29.4)
	Deductions	
8.	Capital cost allowance - Federal	95.4
9.	Capital cost allowance - Provincial	95.4
10.	Items capitalized for regulatory purposes	-
11.	Deduction for "grossed up" Part V1.1 tax	-
12.	Amortization of share and debt issue expense	-
13.	Amortization of cumulative eligible capital	-
14.	Amortization of C.D.E. & C.O.G.P.E.	-
15.	Any other deduction(s)	-
16.	Total Deductions - Federal	95.4
17.	Total Deductions - Provincial	95.4
18.	Taxable income - Federal	(124.8)
19.	Taxable income - Provincial	(124.8)
20.	Income tax provision - Federal	(22.5)
21.	Income tax provision - Provincial	(17.5)
22.	Income tax provision - combined	(40.0)
23.	Part V1.1 tax	-
24.	Investment tax credit	-
25.	Total taxes excluding tax shield on interest expense	(40.0)
	Tax shield on interest expense	
26.	Rate base as adjusted	2,145.1
27.	Return component of debt	4.08%
28.	Interest expense	87.5
29.	Combined tax rate	32.000%
30.	Income tax credit	(28.0)
31.	**Total income taxes**	(68.0)

REVENUE REQUIREMENT
GREEN ENERGY INITIATIVES

($000's)

Line No.		2010
	Cost of capital	
1.	Rate base	2,145.1
2.	Required rate of return	7.07%
3.	Cost of capital	151.7
	Cost of service	
4.	Gas costs	-
5.	Operation and Maintenance	-
6.	Depreciation and amortization	95.4
7.	Municipal and other taxes	29.4
8.	Cost of service	124.8
	Misc. & Non-Op. Rev	
9.	Other operating revenue	-
10.	Other income	-
11.	Misc, & Non-operating Rev.	-
	Income taxes on earnings	
12.	Excluding tax shield	(40.0)
13.	Tax shield provided by interest expense	(28.0)
14.	Income taxes on earnings	(68.0)
	Taxes on (def) / suff.	
15.	Gross (def.) / suff.	(306.6)
16.	Net (def.) / suff.	(208.5)
17.	Taxes on (def.) / suff.	98.1
18.	**Revenue requirement**	306.6
	Revenue at existing Rates	
19.	Gas sales	0.0
20.	Transportation service	0.0
21.	Transmission, compression and storage	0.0
22.	Rounding adjustment	0.0
23.	Revenue at existing rates	0.0
24.	**Gross revenue (def.) / suff.**	(306.6)

Y FACTORS - OTHER

1. This evidence supports the Company's Y-factor adjustments for gas in storage related carrying costs and CIS / Customer Care costs, found within the revenue per customer cap formula evidence at Exhibit B, Tab 1, Schedule 2, page 1. Evidence supporting the Y-factors for DSM, power generation projects, and Green Energy Initiatives can be found in Exhibit B, Tab 2, Schedules 1 through 4.

2. The Company is required to include within its total revenue to be collected in rates determined by the EB-2007-0615 Board approved revenue per customer cap formula, incremental costs related to:

    a. CIS / Customer Care costs that result from the application of the 'True Up Template' approved by the Board in the 2008 Final Rate Order, EB-2007-0615, Appendix F, page 1 (Ref. Exhibit E, Tab 2, Schedule 1); and

    b. Incremental gas costs associated with upstream transportation, storage and supply mix costs relative to the Company's 2010 volumetric forecast. The Company's current 2010 forecast of gas costs to operations is found at Exhibit B, Tab 6, Schedules 1 and 2. Additionally, an adjustment is required to allow for the change in approved rates related to carrying costs of gas in storage and working cash related to gas costs. That is, an adjustment is required to remove the carrying costs associated with the previously approved recovery of the 2009 costs from rates and replace them with the costs associated with the 2010 forecast carrying costs and related working cash that result from the changes inherent in the gas volume budget and associated gas in storage balance. Please refer to Exhibit B, Tab 1, Schedule 2, Appendix A for calculation details.

Witness: K. Culbert

TAB 5

ONTARIO ENERGY BOARD ACT, 1998, S.O. 1998, c. 15 (Schedule B)

Board objectives, gas

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 accordance with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.

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.

Conservation directives

27.1 (1) The Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

Publication

(2) A directive issued under this section shall be published in *The Ontario Gazette*.

PART III
GAS REGULATION

Order of Board required

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.

Order re: rates

(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.

Power of Board

(3) In approving or fixing just and reasonable rates, the Board may adopt any method or technique that it considers appropriate. Contents of order

(4) An order under this section may include conditions, classifications or practices applicable to the sale, transmission, distribution or storage of gas, including rules respecting the calculation of rates.

Orders by Board, electricity rates
Order re: transmission of electricity

78. (3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity or such other activity as may be prescribed and for the retailing of electricity in order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*. 2009, c. 12, Sched. D, s. 12 (1).

78.

TAB 6

Re

Union Gas Ltd. and Ontario Energy Board et al.

[1983] O.J. No. 3191

43 O.R. (2d) 489

1 D.L.R. (4th) 698

22 A.C.W.S. (2d) 301

Ontario
High Court of Justice
Divisional Court
Steele, Anderson

and Saunders JJ.

November 1, 1983.

B. H. Kellock, Q.C., and B. MacL. Rogers, for appellant.

D. H. Rogers, Q.C., for respondent, Ontario Energy Board.

P. C. P. Thompson, Q.C., for respondent, Industrial Gas Users Association.

The judgment of the court was delivered by

1 **ANDERSON J.**:-- This is a motion by Union Gas Limited (Union) for leave to appeal from the order of the Ontario Energy Board (the O.E.B.) issued May 13, 1983, and, if leave be granted, by way of appeal from the said order. The central question for decision is whether the O.E.B., in the course of its rate- making function, having disallowed the appellant an operating cost of which the quantum was not in dispute and the propriety was not in question, committed an error of law or jurisdiction such that this court should intervene on appeal. The provisions of the Ontario Energy Board Act, R.S.O. 1980, c. 332 (the Act), in so far as they are material are in the following terms:

> 32(1) An appeal lies to the Divisional Court from any order of the Board upon a question of law or jurisdiction, but no such appeal lies unless leave to appeal is

> obtained from the court within one month of the making of the order sought to be appealed from or within such further time as the court under the special circumstances of the case allows.
>
> (2) The Board is entitled to be heard by counsel or otherwise upon the argument of any such appeal.
>
> (3) The Divisional Court shall certify its opinion to the Board and the Board shall make an order in accordance with such opinion, but in no case shall such order be retroactive in its effect.

Facts

2 Union conducts an integrated gas utility business which combines the operations of producing, purchasing, transmitting and storing gas ("gas" as defined by s. 1(1), para. 6 of the Act). Union stores and transmits gas for others, sells gas to other utilities for resale and distributes gas to ultimate consumers in its franchise area in south-western Ontario.

3 By application dated July 15, 1982, Union applied to the O.E.B. pursuant to s. 19 of the Act for, inter alia, an order approving or fixing just and reasonable rates and other charges for the sale of gas, and for the storage and transmission of gas for others; such rates to be effective on April 1, 1983, the commencement of Union's 1984 fiscal year.

4 Union's application (given the docket No. E.B.R.O. 388) was supported by pre-filed evidence and by oral testimony and oral and written argument during the hearing. The hearing commenced December 13, 1982, and concluded February 18, 1983. The O.E.B.'s reasons for decision are dated April 22, 1983; the final order was issued May 13, 1983; and the rates thereby established became effective commencing April 22, 1983.

5 In its decision and by its order, the O.E.B. excluded from the amount to be recovered by the rates fixed the sum of $8,693,000, representing a portion of the cost to Union of its gas supplies from Union's major supplier, TransCanada PipeLines Limited ("T.C.P.L."), during the test year (April 1, 1983 to March 31, 1984). The treatment of this item by the O.E.B. is the focal point of this application.

6 Union seeks leave to appeal and, if granted, appeals from the O.E.B. order upon the grounds that the O.E.B. erred in law or exceeded its jurisdiction in purporting to fix just and reasonable rates which do not permit Union the opportunity of recovering through such rates $8,693,000 of Union's cost of gas supplies.

7 The respondent, the O.E.B., exercises jurisdiction over, inter alia, the sale and distribution of gas to consumers, and the construction of facilities to distribute the gas. No distributor such as Union is permitted to sell gas except in accordance with an order of the O.E.B.

8 A distributor desiring to sell gas is required to apply to the O.E.B. for a determination of just and reasonable rates. The O.E.B. is required to determine a rate base and a reasonable return, based upon the evidence adduced in a public hearing.

9 In a rate application, the O.E.B. generally proceeds, as in the case at bar, by determining:

(a) the rate base;

(b) the appropriate rate of return on that rate base;

(c) the applicant's cost of service;

(d) the revenue deficiency (or revenue surplus), and

(e) the appropriate rate increases (or decreases) for each customer class required to meet the deficiency (or surplus).

10 Accordingly, in each rate application the applicant utility structures the evidence filed in support of the application so as to permit the O.E.B. to determine the appropriate rate base and the appropriate cost rates for each element of the capital structure used to finance the rate base, the utility's cost of service and, finally, the amount of the revenue deficiency (if any) that existing rates would produce if they were not altered. These amounts are estimated and determined by the O.E.B. for the period covered by the application, a future "test year" during which the rates to be fixed will be in force.

11 Traditionally, the O.E.B., and most other utility regulators, have set rates based upon an historic "test year" utilizing actual results for a past period.

12 Recently, and in E.B.R.O. 388, some regulated utilities have chosen to seek rates based on a future test year. This requires forecasts or predictions of future conditions.

13 The future test year approach has been accepted by the O.E.B. as appropriate in specific cases. While the approach has certain advantages in times of rising costs, it does require the application of extensive judgment in all areas and increases the uncertainties involved.

14 The rate base is simply the depreciated cost to the utility of Union's property (plant and equipment) "used or useful" in serving the public, e.g., pipelines, compressors, trucks and typewriters, together with allowances for such items as working capital.

15 As Union has investments in unregulated activities (e.g., the development of oil and gas in western Canada), the O.E.B. must determine an appropriate capital structure for the utility operation alone that includes long-term debt, preference shares, common equity capital and short-term borrowings.

16 The O.E.B. then determines the appropriate cost rates for the test year for each component of the capital structure, i.e., long-term and short-term debt, preference shares and common equity.

17 The utility's revenue requirement, which is made up of two components, its total operating costs and an appropriate return on rate base, represents the utility's cost of service for the test year. Operating costs include the cost of gas supplies, pay-roll costs, depreciation and taxes.

18 The revenue deficiency (if any) is calculated by comparing the total cost of service to the total estimated revenues. For this purpose, the rates in effect prior to the application are applied to the estimated volume of gas sales in the test year. The shortfall (if any) is termed the "revenue deficiency".

19 The last step in the process is the determination by the O.E.B. of the specific alterations to be made in the utility's rate structure so as to provide the utility with the opportunity over the test year

to collect sufficient revenues from all classes of customers sufficient to cover the revenue deficiency. The O.E.B. then determines the appropriate rates for each class of customer.

20 Union receives more than 96% of its gas supply from T.C.P.L. in accordance with Union's contractual commitments and T.C.P.L.'s tariffs. The remaining amount is supplied by independent producers and Union's own gas wells in south-western Ontario, and by Petrosar in Sarnia, Ontario. T.C.P.L. delivers its gas from western Canada through its own pipelines to Union and other utilities in accordance with rate schedules approved by the National Energy Board ("N.E.B.").

21 Gas is purchased by Union from T.C.P.L. under three classes of service permitted by the N.E.B.: CD (Contract Demand), ACQ (Annual Contract Quantity) and AOI (Authorized Overrun Interruptible). CD and ACQ services are supplied pursuant to long-term contracts between Union and T.C.P.L. Approximately one-half of the contracted-for gas is purchased under six CD contracts. The other half is purchased under three ACQ contracts. AOI service is only available from time to time upon short notice and, therefore, cannot be relied upon for long- term gas supply.

22 Under CD service, the delivery of a specific quantity of gas, on a daily basis, is guaranteed by T.C.P.L. For this, Union must pay both demand and commodity charges. The demand charges must be paid on a monthly basis, whether or not the quantity of gas contracted for is actually taken. The demand charges represent the minimum monthly bill. In essence, the demand charges are a reservation fee to ensure a constant and secure supply of gas and are intended to recoup T.C.P.L.'s fixed costs for the CD service contracted for, recognizing that T.C.P.L. must have continually available the facilities that are necessary to deliver CD service gas on a daily basis. In addition, commodity charges are payable for the quantity of gas actually taken by Union in any particular month under the CD service contracts. Therefore, unlike the demand charges, commodity charges will vary directly with actual volumes delivered. Since the quantities guaranteed for delivery are fixed by contract, demand charges will remain constant for the period of the contract, except for changes in T.C.P.L.'s tariffs.

23 ACQ service is the lowest price supply service available to Union from T.C.P.L. While the price of ACQ service is lower than CD service, ACQ is offered on an interruptible basis. Union is required to pay the full cost of the annual quantities of gas contracted for, whether or not Union can accept delivery of such quantities. The quantity Union is committed to take annually (and T.C.P.L. to supply) can be reduced by no more than 10% in any year, and then only if 18 months' prior notice is given by Union to T.C.P.L. Because of the interruptible nature of ACQ service, a great deal of storage capacity is required.

24 AOI service is available only when T.C.P.L. has a surplus of both gas and delivery capacity, and is offered in specific quantities and on short notice.

25 Union has been able in the past to take full levels of both ACQ and CD service. By taking CD service at "100% load factor", or the full contracted quantity, the demand charge component of the price for this gas has been spread over the maximum volume (or units) of gas. This reduces the unit cost of CD service gas and keeps it close to that of ACQ service gas. All of the demand charges are said to be fully "absorbed" when CD service gas is purchased at 100% load factor. "Unabsorbed demand charges" occur whenever a utility is unable to take the full volumes that have been contracted for.

26 As a gas utility, Union must meet customers' requirements while keeping gas costs as low as possible. Union must therefore enter into long-term contracts (20 years or more) that commit Union

to purchasing specific quantities of gas over many years. When an unexpected and temporary economic downturn causes the demand for gas to fall, Union can maximize its use of storage capacity or cut back the quantity of CD service taken.

27 Union must, looking into the future, make a determination of its gas supply strategy by assessing many different factors. These include maximum and optimum storage levels, anticipated future increases in the price of gas, anticipated gas sales in the future and effect of CD service cutbacks on the price of gas for contract customers with price escalation provisions in their contracts with Union. These and other factors must be predicted for some time in the future and all but the volume of gas kept in storage are out of Union's control.

28 Whatever strategy is finally determined, an economic downturn causes the unit cost of gas to Union to increase. When the quantity of gas contracted for exceeds the quantities that can be sold, increased carrying costs of gas in storage or demand charges for the CD service that are no longer spread over the full quantities contracted for, or both, will be incurred.

29 Union's gas sales volumes fell substantially in fiscal year 1983 (April 1, 1982 to March 31, 1983) from those forecast in O.E.B. rate case E.B.R.O. 382 (which fixed rates for that year). The pre-filed evidence in E.B.R.O. 388 reflected an estimated reduction in sales from the E.B.R.O. 382 forecast. This estimate was revised twice before the final estimate was filed. The final sales volume estimates filed in E.B.R.O. 388 likewise indicated substantially reduced sales. Sales in fiscal year 1985 were also forecast to decrease. The provisions of Union's long-term contracts with T.C.P.L. combined with reduction in sales produced a substantial gas supply surplus. The decision was made by Union in 1982 to maximize the use of storage and thereby to reduce CD service. This almost totally used Union's storage capacity but was of benefit to Union by minimizing the unit cost of gas. A cut-back in the CD service was forecast for the E.B.R.O. 388 test year (1984). The reductions in sales meant that in the test year 1984 the cost of gas would be $8,693,000 more than if the CD service was continued at 100% load factor. This amount, described as unabsorbed demand charges, is a direct cost of gas to Union in the test year 1984.

30 As to the return to common shareholders, the board had the evidence of three expert witnesses. The lowest estimate was given by the witness Parcell, in whose opinion a range of 15% to 16% represented the cost of equity capital for Union Gas' utility operations. The O.E.B. found a rate of 15.6% to be appropriate. The O.E.B. then determined the appropriate revenue deficiency for the purpose of fixing the rates.

Issues and law

31 The rate-making jurisdiction of the O.E.B. is found in s. 19 of the Act which, in so far as material to these proceedings, is in the following terms:

> 19(1) Subject to the regulations, the Board may make orders approving or fixing just and reasonable rates and other charges for the sale of gas by transmitters, distributors and storage companies, and for the transmission, distribution and storage of gas.
>
> (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 com-

pany, and shall determine whether the return on the rate base produced or to be produced by such rates and other charges is reasonable.

(3) The rate base to be determined by the Board under subsection (2) 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.

(4) In determining the reasonable allowance for the cost of the property under clause (3)(a), the Board shall ascertain the actual cost of the property to the present owner, but,

(a) where the actual cost to the present owner of any of the property cannot be ascertained, the Board shall determine a reasonable allowance to be included in the rate base for the cost of that property; and

(b) where in the opinion of the Board the actual cost to the present owner of any of the property is more than a reasonable allowance for inclusion in the rate base for the cost of that property, the Board shall determine a reasonable allowance to be included in the rate base for the cost of that property.

(5) In considering whether the actual cost mentioned in subsection (4) exceeds a reasonable allowance for inclusion in the rate base and in determining the appropriate deductions to be made in respect of any such excess, the Board may consider all matters it considers relevant, including the public benefit resulting from the acquisition of the property, whether the acquisition at the price paid was prudent in the circumstances existing at the time and, where the property was acquired as an operating system or part thereof, the allowance made for its cost in the rate base of the former owner or, if no such rate base had been determined that included an allowance for the cost thereof, the allowance that would have been made therefor in a rate base for the former owner determined in accordance with this section.

(6) Findings of fact on which determinations are made by the Board under subsections (2), (3), (4) and (5) shall be based on the evidence adduced at the hearing.

32 The phrases "just and reasonable" or "fair and reasonable", "rate base" and "used or useful" have been employed to describe the principles and methodology to be used by public utility boards and commissions in fixing public utility rates in the United States and Canada for many years. See, for example, Northwestern Utilities, Ltd. v. City of Edmonton et al., [1929] S.C.R. 186, [1929] 2 D.L.R. 4, per Lamont J. at pp. 192-3 S.C.R., p. 8 D.L.R.:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

33 In support of its motion for leave and if appeal be granted, in support of its appeal, the appellant makes the following submissions:

(1) In order to be just and reasonable, the rates fixed must:

(a) cover the utility's operating cost, and

(b) provide appropriate compensation to the owners of the utility over and above the cost of providing the service.

(2) That the Act does not provide the O.E.B. with authority or jurisdiction to act as manager of the appellant's utility operation, to determine its operating costs arbitrarily, or to exercise an unlimited discretion.

(3) That the result of the O.E.B. decision is to deprive Union of its property without adequate compensation, in contravention of the language and intent of the Act.

(4) That once the appellant's gas purchase decisions have been found to be reasonable, it follows, a fortiori, that the purchase price of such gas must be found to be a reasonable operating expense and must be included in the calculation of the rates to be fixed and recoverable by the appellant.

34 The position of the respondent O.E.B. with which the other respondent associated itself, is that no issue of law or jurisdiction is involved. The respondent submits that:

(a) the O.E.B. is given wide powers and broad discretion to fix rates which in its opinion are "just and reasonable";

(b) that the determination of the cost of service is not strictly an issue of law or jurisdiction and is a matter in which the court should not substitute its opinion for that of the board;

(c) that in determining rates which are just and reasonable the O.E.B. should balance the interest of the customers (ratepayers) and those of the owners (shareholders);

(d) that the O.E.B. should consider the conflicting interests of present and future customers.

35 In the oral argument two principal areas of difference emerged.

36 The respondents contended that the decisions taken by the appellant to continue in fiscal year 1983 to fulfil its CD contracts and to use its storage facilities to the greatest extent possible had the effect of avoiding, for that period, unabsorbed demand charges which would otherwise have been a charge to the shareholders. It was further contended that, if the unabsorbed demand charges which resulted in the test year were allowed in full, they would operate to the detriment of customers of the utility during that year. They submitted that the disposition by the board of the over-supply problem and the disallowance of the unabsorbed demand charges represented a sharing of the latter between the shareholders and the customers of the utility, and that it was within the due and proper discretion of the O.E.B. to effect such a sharing in those circumstances.

37 On these points, counsel for the appellant first submitted that Union's decision to follow the course which it did follow with respect to the over-supply problem was a legitimate management technique as to which no adverse finding was made by the O.E.B. He further submitted that the O.E.B. had no discretion or jurisdiction to effect such a sharing as to an operating cost. He submitted that, in the instant case, such sharing had the effect of reducing the return on equity from 15.6%, which on the evidence the O.E.B. had found to be appropriate, to 13.75%, which, he submitted, found no support on the evidence.

38 The arguments of counsel for the respondents may be related to concerns expressed by the O.E.B. in its reasons for decision:

> The treatment to be accorded the volume of gas in storage was one of the main issues in this hearing. As outlined later in the gas sales forecast section of these Reasons for Decision, the Company found itself in an acute gas over- supply position. However, Union proposed that only a part of the excess gas be included in inventory and consequently in rate base and that the remainder, valued at $52 million, be segregated in the capital structure as a "special assignment". As well, Union also forecasted a test year cut- back in the Contract Demand ("CD") gas supply contract of 372 106m3 which would result in unabsorbed demand charges of $8.693 million and which the Company proposed be included in its cost of gas for the test year. As the unabsorbed demand charges also result from the gas over-supply situation, the Board will include discussion of these proposals together with the excess gas in storage, in this section. The special assignment however, is discussed under its own heading in these Reasons for Decision.
>
> IGUA submitted that the total value of the over-supply ought to be excluded from rate base, but the cost of financing it ought to be included in the utility's cost of service for the test year and distributed on a demand rather than a commodity basis. Mr. Thompson submitted that the rate base for the test year as put

forward by Union reflects this abnormally and unacceptably high level of gas in storage and a reduction ought to be made to reflect normal conditions.

Mr. Thompson estimated that the value of the excess gas in storage was approximately $100 million and he argued that Union's ratebase ought to be reduced by that amount and the cost of service should be increased by $12 million to provide for the cost of carrying that $100 million worth of excess gas.

Mr. Kawalec in his argument took issue with Union's entire proposal to charge its customers the excess carrying costs. He submitted that:

"The Board [should] not bail out Union on every excess supply problem. One Petrosar is enough. This problem should rightfully reach the shareholders, and they can hold management accountable for this excess gas supply."

Board Counsel submitted that Union, in attempting to alleviate the drastic over-supply problem in the 1983 fiscal year and the test year took the following steps:

1. deferred 122 106m3 of Annual Contract Quantity ("ACQ") purchases from the 1983 fiscal year to the test year, and then the same amount from the test year to the 1985 fiscal year;
2. curtailed 219 106m3 of ACQ purchases in the test year;
3. curtailed the purchases of ACQ gas by a further 10% in the test year;
4. reduced volumes for its short-term storage customers in the test year by 230 106m3 and increased its long-term storage volumes by 88 106m3; and
5. agreed with Consumers' that 77 106m3 of ACQ deliveries would be delayed from the 1983 fiscal year to the test year.

Board Counsel submitted that Union was transferring 198 106m3 of gas from the 1983 fiscal year to the test year. The major reason for this he submitted, was that if a CD curtailment had taken place during the 1983 fiscal year, Union's shareholders would have absorbed the total cost but if the curtailment were to take place during the test year as Union proposed, the cost would be transferred to customers in the test year.

Mr. Rogers also argued that the deferral of the 122 106m3 of ACQ gas from 1983 to 1984 and then subsequently to 1985, effectively denied the 1984 customers a benefit by removing a potential deferral and using that deferral for excess 1983 volumes. Thus, he argued, the customers in the test year are really being asked to pay for gas costs that should properly be assigned to the 1983 fiscal year. He submitted that:

"Union has endeavoured to manage its gas supply picture so as to maximize the shareholder benefit first and then to the extent it's still possible pass some benefit to the customer. This clearly is not considered appropriate."

Mr. Kellock argued that no portion of legitimate gas costs should be disallowed without evidence of "fault, bad faith, negligence or abuse of discretion." He pointed out that Union was "not in possession of a crystal ball" and could not have altered its gas supply arrangements so as to produce a lower level of costs than that claimed. He contended that cut-backs in CD deliveries must be made over the next two years and the claimed cut-back of 372 106m3 for the test year is unavoidable. Such cut-backs are common to all three major gas utilities in Ontario, he said.

In regard to Mr. Rogers' argument about the lowering of the proposed test year cut-back to account for the fact that there should have been a cut-back in 1983, Mr. Kellock pointed out that as the ACQ deferral from 1983 is actually passed through to 1985 it does not have any effect on the test year. He said that the Consumers' arrangements in regard to storage delivery were made for Consumers' benefit and had no impact on the need for a CD cut-back in 1983. He also argued that the Consumers' short-term storage arrangements in 1983 had no impact on the level of the CD cut-back in 1984 since a like amount has been subsequently deferred through to the 1985 fiscal year. As well, he pointed out that an unscheduled cut-back in 1983 would have an adverse impact on Union's customers which have price escalations in their supply contracts.

The Board in examining the evidence is concerned about the carry-over of excess gas from the 1983 fiscal year to the test year. Mr. Kellock argued that: "because of the success of Union's negotiations with TCPL, it became evident that no cut-backs were needed for fiscal year 1983." This he pointed out, saved a further erosion in sale volumes which would have resulted from a price increase caused by the pass-through of unabsorbed demand charges to the contracts with price escalation.

There is no doubt that these points are valid reasons why a cut-back should not have taken place in the 1983 fiscal year. Union has testified that in the circumstances, storing the excess gas and paying the extra carrying cost was preferable to a cut-back.

The Board's concern is that by so doing Union has forced the cost of cut-backs on its 1984 customers. By putting the excess gas during fiscal 1983 into storage, Union has effectively reduced the storage space for any excess gas in 1984 and as the rates for 1983 were set a year ago, and did not take into account that excess, part of the cost of the excess gas should be borne by Union's shareholders. If the opposite had been the case and Union had sold more gas than was forecast

> when the rates were set, that extra revenue would have belonged to the shareholders and for that reason Union must bear some of the costs associated with the downturn in gas sales.
>
> In so far as the argument was made that the CD contracts are essential, primarily for security of supply and that security of supply is a cost responsibility of customers, the Board is of the opinion that although security of supply is vital to Union's customers, it is also vital to its shareholders. Risk of an economic downturn is a risk that rests on Union's shareholders and they are compensated for it in the return on common equity.
>
> Mr. Black's evidence was that in Union's last rate case there was available 376.1 106m3 of extra storage space and as well, a total of 330 106m3 of Authorized Overrun Interruptible ("AOI") gas which could be cancelled without notice. This amounted to a total "downside coverage" of 706.1 106m3 for the fiscal years 1983 and 1984. The ultimate result however was that Union, although it covered a large part of its sales downturn, did not do so without considerable cost. As stated earlier, Union's shareholders must bear part of the cost of the over-supply because of the sales downturn in 1983 for which the 1984 customers are not responsible.
>
> The Board will therefore allow in rate base the value of the gas in inventory as proposed by Union save and except the value of the special assignment and will also disallow all forecasted unabsorbed demand charges.

39 It was basic to the submissions on behalf of both respondents that the rate-making process is an involved and technical one as to which the O.E.B. has special expertise. The hearing was lengthy and the reasons of the O.E.B. detailed and voluminous. The relevant textbooks and authorities are replete with admonitions that a court should be reluctant to interfere with the dispositions of such tribunals, and should do so only in circumstances which clearly require it. See, for example, Re Western Ontario Credit Corp. Ltd. and Ontario Securities Com'n (1975), 9 O.R. (2d) 93, 59 D.L.R. (3d) 501, where, at p. 103 O.R., p. 511 D.L.R., Hughes J. has this to say:

> ... where a regulatory tribunal, acting within its jurisdiction, makes an order in the public interest with the experience and understanding of what that interest consists of in a specialized field accumulated over many years, the Court will be especially loath to interfere.

It is with such admonitions as that in mind that I approach the disposition of this case.

40 By way of general observation, it may also be said that in the field of law with which this case is concerned there are substantial similarities between the situation here and in the United States, and authorities of courts in the United States are frequently referred to and considered in cases of this kind. In the case at bar, reference was made by counsel for all parties to both textbooks and cases originating in the United States.

41 As general background in considering the rate-making function performed by the O.E.B. it is useful to consider a quotation from Principles of Public Utility Regulation by A.J.G. Priest. At p. 4, the learned author quotes a speaker on this subject in the following terms:

> "In the United States, private enterprise operates a larger share of these vital industries than in almost any other country because of our balanced system of regulation by public authority. This system is designed to protect consumers against exploitation where competition is inherently unavailable or inadequate, and to ensure that these industries will serve the public interest. At the same time it provides these companies necessary assurance of an opportunity to earn a reasonable return on their investment and to attract capital for expansion."

Put another way, 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.

42 That in balancing these conflicting interests and determining rates that are just and reasonable the O.E.B. has a wide discretion, is not in issue or in doubt. Findings of fact upon which its determinations under s-ss. (2), (3), (4) and (5) of s. 19 of the Act are made are required by s-s. (6) to be based on the evidence adduced at the hearing. In the exercise of that discretion and subject to that requirement, for the purpose of determining a rate base, the O.E.B. can fix a reasonable allowance for the cost of the property that is "used or useful" in providing service, a reasonable allowance for working capital and such other amounts as, in its opinion, are fit to be included. In the instant case, for example, it adjusted, determined, and allowed amounts for gas in storage and working capital. It declined to allow a change in accounting policy as applied to capitalization of overhead expenses. It approved a capital structure including long-term debt, short-term debt, preference shares and equity. In this context, it allowed a "special assignment" of $52 million for gas in storage. Likewise, in determining cost of service, the O.E.B. has a wide discretion as to what will be included and in what amount. It can apportion common costs as between utility and non-utility operations.

43 Looking at the obligation of the O.E.B. to have regard for the interests of the appellant, the O.E.B. is under an obligation to approve rates which will produce a fair return. In British Columbia Electric R. Co. Ltd. v. Public Utilities Com'n of British Columbia et al., [1960] S.C.R. 837, 25 D.L.R. (2d) 689, 33 W.W.R. 97, Locke J. says, at p. 848 S.C.R., p. 698 D.L.R.:

> The obligation to approve rates which will produce the fair return to which the utility has been found entitled is, in my opinion, absolute ... The Commission is directed by s. 16(1) (a) to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute.

44 The question of what is a fair return is addressed in North- western Utilities, Ltd. v. City of Edmonton et al., [1929] S.C.R. 186, [1929] 2 D.L.R. 4, where, at p. 193 S.C.R., p. 8 D.L.R., is found the following language in the judgment of Lamont J.:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would

> receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

(Emphasis added.) The provision of the fair return is essential to preservation of the financial integrity of the appellant which is of mutual concern both to the appellant and to its customers.

45 The relatively narrow question presented by the appellant for determination by this court concerns the disallowance of the $8,693,000 of unabsorbed demand charges which were forecast for the test year and whether such disallowance was a question of law or jurisdiction such as to give rise to a right of appeal under s. 32 of the Act.

46 I am not satisfied that the item of $8,693,000 can be dealt with thus in isolation. It was not so dealt with by the O.E.B.

47 It is apparent from the reasons for decision, and in particular the portions quoted above, that the O.E.B. dealt with this item as part of its consideration of the whole question of over-supply of gas. This included its treatment of gas in storage as well as the disputed item. It is only fair to conclude that its disposition of the problem of gas in storage, necessary in determination of the rate base, and as to which no sound objection could be taken, was related to and conditioned by its concomitant disposition of the disputed item.

48 The O.E.B. has a wide discretion as has already been observed to allow, disallow or adjust the components of both rate base and expense. It may not, in the exercise of its discretion, be arbitrary or capricious in either area. It therefore ought not, as a general rule, to disallow an item of expense which will be properly incurred by the utility.

49 I am not persuaded that it did so in this case. Considered as one factor in dealing with the whole problem of over-supply of gas, it cannot be said that the disallowance was arbitrary or capricious. In my view, it did not involve any reversible error of law or jurisdiction.

50 At the same time, the appeal does raise a question of law or jurisdiction as to which leave ought properly to be granted.

51 I would grant leave but dismiss the appeal. I would give the respondent I.G.U.A. its costs and make no other order as to costs.

Leave to appeal granted; appeal dismissed.

TAB 7

Case Name:

Advocacy Centre for Tenants-Ontario v. Ontario (Energy Board)

Between
Advocacy Centre for Tenants-Ontario and Income Security Advocacy Centre on behalf of Low-Income Energy Network, Appellant, and
Ontario Energy Board, Respondent

[2008] O.J. No. 1970

293 D.L.R. (4th) 684

166 A.C.W.S. (3d) 384

238 O.A.C. 343

Court File No.: 273/07

Ontario Superior Court of Justice
Divisional Court - Toronto, Ontario

F.P. Kiteley, P.A. Cumming and K.E. Swinton JJ.

Heard: February 25, 2008.
Judgment: May 16, 2008.

(111 paras.)

Natural resources law -- Public utilities -- Operation of utility -- Terms and conditions of service -- Collection or rates and charges -- Toll methodology -- Just and reasonable tolls -- Rates -- Regulation rationale -- Appeal of Ontario Energy Board's decision that it had no jurisdiction to order a "rate affordability assistance program" under the Ontario Energy Board Act allowed with dissent -- The board had the jurisdiction to take into account the ability to pay in setting rates given the expansive wording of s. 36(2) and (3) 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 -- Ontario Energy Board Act, s. 2, s. 36(2), s. 36(3).

Appeal under s. 33 of the Ontario Energy Board Act seeking a declaration that the board had the jurisdiction to order a "rate affordability assistance program" for low income consumers of the utility, Enbridge Gas Distribution Inc., within its franchise areas as the distributor of natural gas. By a majority decision of April 26, 2007, the board determined that the Act did not explicitly grant the board jurisdiction to order the implementation of a low income affordability program. The board also found it did not gain the requisite jurisdiction through the doctrine of necessary implication. Presently, EGD, the board and the intervenor Consumers Counsel of Canada argued that the issue was one of public policy to be dealt with by the Legislature falling outside the board's jurisdiction.

HELD: Appeal allowed (with dissent). The board had the jurisdiction to establish a rate affordability assistance program for low income consumers purchasing the distribution of natural gas from the utility. The board had the jurisdiction to take into account the ability to pay in setting rates. The court found so 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. Such an interpretation complied with the legislative text, it promoted the legislative purpose and the outcome was reasonable and just. The jurisdiction to consider ability to pay in rate setting was explicitly within the Act. The board was an economic regulator rather than a formulator of social policy. However, the board was authorized to employ "any method or technique that it considers appropriate" to fix "just and reasonable rates".

Statutes, Regulations and Rules Cited:

Canadian Charter of Rights and Freedoms, R.S.C. 1985, App. II, No. 44, Schedule B, s. 15

Income Tax Act, R.S.O. 1990, c. I.2, s. 8.6.1

Income Tax Amendment Act (Ontario Home Electricity Relief), 2006, S.O. 2006, c. 18, s. 1

Energy Costs Assistance Measures Act, S.C. 2005, c. 49,

Legislation Act, S.O. 2006, c. 21, Schedule F, s. 64(1)

Ontario Energy Board Act, R.S.O. 1980, c. 332, s. 19

Ontario Energy Board Act, 1988, S.O. 1998, c. 15, Schedule B, s. 33, s. 36, s. 79

Power Corporation Act, R.S.O. 1990, c. P.18, s. 108

Counsel:

Paul Manning and ***Mary Truemner***, for the Appellant.

Michael Miller, for Ontario Energy Board.

Fred Cass and ***David Stevens***, for Enbridge Gas Distribution Inc.

Robert Warren, for Consumers Council of Canada.

Reasons for judgment were delivered by F.P. Kiteley and P.A. Cumming JJ. Separate dissenting reasons were delivered by K.E. Swinton J.

F.P. KITELEY and P.A. 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.

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.

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.

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

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 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 cau-

sality 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.
>
> 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.

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 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.), 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.

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).

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.

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.

F.P. KITELEY J.
P.A. CUMMING J.

70 K.E. SWINTON J. (dissenting):-- 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 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 rate-making 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] 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).

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 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*).

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 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.

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.

K.E. SWINTON J.

cp/e/qljxk/qlclg/qltxp/qlcxm/qlcas/qlaxw/qlhcs/qlaxw

TAB 8

Indexed as:

ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)

City of Calgary, appellant/respondent on cross-appeal;
v.
ATCO Gas and Pipelines Ltd., respondent/appellant on cross-appeal, and
Alberta Energy and Utilities Board, Ontario Energy Board, Enbridge Gas Distribution Inc. and Union Gas Limited, interveners.

[2006] 1 S.C.R. 140

[2006] S.C.J. No. 4

2006 SCC 4

File No.: 30247.

Supreme Court of Canada

Heard: May 11, 2005;
Judgment: February 9, 2006.

Present: McLachlin C.J. and Bastarache, Binnie, LeBel, Deschamps, Fish and Charron JJ.

(149 paras.)

Appeal From:

ON APPEAL FROM THE COURT OF APPEAL FOR ALBERTA

Catchwords:

Administrative law — Boards and tribunals — Regulatory boards — Jurisdiction — Doctrine of jurisdiction by necessary implication — Natural gas public utility applying to Alberta Energy and Utilities Board to approve sale of buildings and land no longer required in supplying natural gas — Board approving sale subject to condition that portion of sale proceeds be allocated to ratepaying customers of utility — Whether Board had explicit or implicit jurisdiction to allocate proceeds of sale — If so, whether Board's decision to exercise discretion to protect public interest by allocating proceeds of utility asset sale to customers reasonable — Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) — Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 — Gas Utilities Act, R.S.A. 2000, c. G-5, s. 26(2).

Administrative law — Judicial review — Standard of review — Alberta Energy and Utilities Board — Standard [page141] of review applicable to Board's jurisdiction to allocate proceeds from sale of public utility assets to ratepayers — Standard of review applicable to Board's decision to exercise discretion to allocate proceeds of sale — Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, s. 15(3) — Public Utilities Board Act, R.S.A. 2000, c. P-45, s. 37 — Gas Utilities

Act, R.S.A. 2000, c. G-5, s. 26(2).

Summary:

ATCO is a public utility in Alberta which delivers natural gas. A division of ATCO filed an application with the Alberta Energy and Utilities Board for approval of the sale of buildings and land located in Calgary, as required by the *Gas Utilities Act* ("GUA"). According to ATCO, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to ratepaying customers. ATCO requested that the Board approve the sale transaction, as well as the proposed disposition of the sale proceeds: to retire the remaining book value of the sold assets, to recover the disposition costs, and to recognize that the balance of the profits resulting from the sale should be paid to ATCO's shareholders. The customers' interests were represented by the City of Calgary, who opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

Persuaded that customers would not be harmed by the sale, the Board approved the sale transaction on the basis that customers would not "be exposed to the risk of financial harm as a result of the Sale that could not be examined in a future proceeding". In a second decision, the Board determined the allocation of net sale proceeds. The Board held that it had the jurisdiction to approve a proposed disposition of sale proceeds subject to appropriate conditions to protect the public interest, pursuant to the powers granted to it under s. 15(3) of the *Alberta Energy and Utilities Board Act* ("AEUBA"). The Board applied a formula which recognizes profits realized when proceeds of sale exceed the original cost can be shared between customers and shareholders, and allocated a portion of the net gain on the sale to the ratepaying customers. The Alberta Court of Appeal set aside the Board's decision, referring the matter back to the Board to allocate the entire remainder of the proceeds to ATCO.

Held (McLachlin C.J. and Binnie and Fish JJ. dissenting): The appeal is dismissed and the cross-appeal is allowed.

Per Bastarache, LeBel, Deschamps and Charron JJ.: When the relevant factors of the pragmatic and functional approach are properly considered, the standard of [page142] review applicable to the Board's decision on the issue of jurisdiction is correctness. Here, the Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset. The Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate any portion of the proceeds of sale of the property to ratepayers. [paras. 21-34]

The interpretation of the AEUBA, the *Public Utilities Board Act* ("PUBA") and the GUA can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. On their grammatical and ordinary meaning, s. 26(2) GUA, s. 15(3) AEUBA and s. 37 PUBA are silent as to the Board's power to deal with sale proceeds. Section 26(2) GUA conferred on the Board the power to approve a transaction without more. The intended meaning of the Board's power pursuant to s. 15(3) AEUBA to impose conditions on an order that the Board considers necessary in the public interest, as well as the general power in s. 37 PUBA, is lost when the provisions are read in isolation. They are, on their own, vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to any order it makes. While the concept of "public interest" is very wide and elastic, the Board cannot be given total discretion over its limitations. These seemingly broad powers must be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The context indicates that the limits of the Board's powers are grounded in its main function of fixing just and reasonable rates and in protecting the integrity and dependability of the supply system. [para. 7] [para. 41] [para. 43] [para. 46]

An examination of the historical background of public utilities regulation in Alberta generally, and

the legislation in respect of the powers of the Alberta Energy and Utilities Board in particular, reveals that nowhere is there a mention of the authority for the Board to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights. Moreover, although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, [page143] the PUBA and the GUA that the principal function of the Board in respect of public utilities, is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates. The goals of sustainability, equity and efficiency, which underlie the reasoning as to how rates are fixed, have resulted in an economic and social arrangement which ensures that all customers have access to the utility at a fair price -- nothing more. The rates paid by customers do not incorporate acquiring ownership or control of the utility's assets. The object of the statutes is to protect both the customer and the investor, and the Board's responsibility is to maintain a tariff that enhances the economic benefits to consumers and investors of the utility. This well-balanced regulatory arrangement does not, however, cancel the private nature of the utility. The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. [paras. 54-69]

Not only is the power to allocate the proceeds of the sale absent from the explicit language of the legislation, but it cannot be implied from the statutory regime as necessarily incidental to the explicit powers. For the doctrine of jurisdiction by necessary implication to apply, there must be evidence that the exercise of that power is a practical necessity for the Board to accomplish the objects prescribed by the legislature, something which is absent in this case. Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that broadly drawn powers, such as those found in the AEUBA, the GUA and the PUBA, can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation. [para. 39] [paras. 77-80]

Notwithstanding the conclusion that the Board lacked jurisdiction, its decision to exercise its discretion to protect the public interest by allocating the sale proceeds as it did to ratepaying customers did not meet a reasonable standard. When it explicitly concluded [page144] that no harm would ensue to customers from the sale of the asset, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Finally, it cannot be concluded that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process. [paras. 82-85]

Per McLachlin C.J. and Binnie and Fish JJ. (dissenting) : The Board's decision should be restored. Section 15(3) AEUBA authorized the Board, in dealing with ATCO's application to approve the sale of the subject land and buildings, to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" pursuant to s. 22(1) GUA, the Board made an allocation of the net gain for public policy reasons. The Board's discretion is not unlimited and must be exercised in good faith for its intended purpose. Here, in allocating one third of the net gain to ATCO and two thirds to the rate base, the Board explained that it was proper to balance the interests of both shareholders and ratepayers. In the Board's view to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs, but on the other hand to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business. Although it was open to the Board to allow ATCO's application for the entire profit, the solution it adopted in this case is well within the range of reasonable options. The "public interest" is largely and inherently a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, Alberta's grant of authority to its Board is more generous than most. The Court should not substitute its own view of what is "necessary in the public interest". The Board's decision made in the exercise of its jurisdiction was within the range of established regulatory opinion, whether the proper standard of review in that regard is patent unreasonableness or simple reasonableness. [paras. 91-92] [paras. 98-99] [para. 110] [para. 113] [para. 122] [para. 148]

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ATCO's submission that an allocation of profit to the customers would amount to a confiscation of the corporation's property overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the ratepayers carry the costs and the regulator sets the return on investment, not the marketplace. The Board's response cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what is regarded in comparable jurisdictions as an appropriate regulatory allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. Similarly, ATCO's argument that the Board engaged in impermissible retroactive rate making should not be accepted. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective not retroactive. Fixing the going-forward rate of return, as well as general supervision of "all gas utilities, and the owners of them", were matters squarely within the Board's statutory mandate. ATCO also submits in its cross-appeal that the Court of Appeal erred in drawing a distinction between gains on sale of land whose original cost is not depreciated and depreciated property, such as buildings. A review of regulatory practice shows that many, but not all, regulators reject the relevance of this distinction. The point is not that the regulator must reject any such distinction but, rather, that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. Finally, ATCO's contention that it alone is burdened with the risk on land that declines in value overlooks the fact that in a falling market the utility continues to be entitled to a rate of return on its original investment, even if the market value at the time is substantially less than its original investment. Further, it seems such losses are taken into account in the ongoing rate-setting process. [para. 93] [paras. 123-147]

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By Bastarache J.

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Line Pilots Assn., [1993] 3 S.C.R. 724; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26; *Chieu v. Canada (Minister of Citizenship and Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3; *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722; *R. v. McIntosh*, [1995] 1 S.C.R. 686; *Re Dow Chemical Canada Inc. and Union Gas Ltd.* (1982), 141 D.L.R. (3d) 641, aff'd (1983), 42 O.R. (2d) 731; *Interprovincial Pipe Line Ltd. v. National Energy Board*, [1978] 1 F.C. 601; *Canadian Broadcasting League v. Canadian Radio-television and Telecommunications Commission*, [1983] 1 F.C. 182, aff'd [1985] 1 S.C.R. 174; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186; *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984; *Re Union Gas Ltd. and Ontario Energy Board* (1983), 1 D.L.R. (4th) 698 ; *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989); *Market St. Ry. Co. v. Railroad Commission of State of California*, 324 U.S. 548 (1945); *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Consumers' Gas Co.*, E.B.R.O. 410-II, 411-II, 412-II, March 23, 1987; *National Energy Board Act (Can.) (Re)*, [1986] 3 F.C. 275; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64; *Leiriao v. Val-Bélair (Town)*, [1991] 3 S.C.R. 349 [page147]; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167.

By Binnie J. (dissenting)

Atco Ltd. v. Calgary Power Ltd., [1982] 2 S.C.R. 557; *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1 S.C.R. 539, 2003 SCC 29; *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171; *Dr. Q v. College of Physicians and Surgeons of British Columbia*, [2003] 1 S.C.R. 226, 2003 SCC 19; *Calgary Power Ltd. v. Copithorne*, [1959] S.C.R. 24; *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316; *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557; *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353; *Union Gas Co. of Canada Ltd. v. Sydenham Gas and Petroleum Co.*, [1957] S.C.R. 185; *Re C.T.C. Dealer Holdings Ltd. and Ontario Securities Commission* (1987), 59 O.R. (2d) 79; *Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37; *Re Consumers' Gas Co.*, E.B.R.O. 341-I, June 30, 1976; *Re Boston Gas Co.*, 49 P.U.R. 4th 1 (1982); *Re Consumers' Gas Co.*, E.B.R.O. 465, March 1, 1991; *Re Natural Resource Gas Ltd.*, O.E.B., RP-2002-0147, EB-2002-0446, June 27, 2003; *Yukon Energy Corp. v. Utilities Board* (1996), 74 B.C.A.C. 58; *Re Arizona Public Service Co.*, 91 P.U.R. 4th 337 (1988); *Re Southern California Water Co.*, 43 C.P.U.C. 2d 596 (1992); *Re Southern California Gas Co.*, 118 P.U.R. 4th 81 (1990); *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (1973); *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (1976); *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684; *New York Water Service Corp. v. Public Service Commission*, 208 N.Y.S.2d 857 (1960); *Re Compliance with the Energy Policy Act of 1992*, 62 C.P.U.C. 2d 517 (1995); *Re California Water Service Co.*, 66 C.P.U.C. 2d 100 (1996); *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984; *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84115, October 12, 1984; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984.

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History and Disposition:

APPEAL and CROSS-APPEAL from a judgment of the Alberta Court of Appeal (Wittmann J.A. and LoVecchio J. (*ad hoc*)) (2004), 24 Alta. L.R. (4th) 205, 339 A.R. 250, 312 W.A.C. 250, [2004] 4 W.W.R. 239, [2004] A.J. No. 45 (QL), 2004 ABCA 3, reversing a decision of the Alberta Energy and Utilities Board, [2002] A.E.U.B.D. No. 52 (QL). Appeal dismissed and cross-appeal allowed, McLachlin C.J. and Binnie and Fish JJ. dissenting.

Counsel:

Brian K. O'Ferrall and Daron K. Naffin, for the appellant/respondent on cross-appeal.

Clifton D. O'Brien, Q.C., Lawrence E. Smith, Q.C., H. Martin Kay, Q.C., and Laurie A. Goldbach, for the respondent/appellant on cross-appeal.

J. Richard McKee and Renée Marx, for the intervener the Alberta Energy and Utilities Board.

Written submissions only by George Vegh and Michael W. Lyle, for the intervener the Ontario Energy Board.

Written submissions only by J. L. McDougall, Q.C., and Michael D. Schafler, for the intervener Enbridge Gas Distribution Inc.

Written submissions only by Michael A. Penny and Susan Kushneryk, for the intervener Union Gas Limited.

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The judgment of Bastarache, LeBel, Deschamps and Charron JJ. was delivered by

BASTARACHE J.:—

1. Introduction

1 At the heart of this appeal is the issue of the jurisdiction of an administrative board. More specifically, the Court must consider whether, on the appropriate standard of review, this utility board appropriately set out the limits of its powers and discretion.

2 Few areas of our lives are now untouched by regulation. Telephone, rail, airline, trucking, foreign investment, insurance, capital markets, broadcasting licences and content, banking, food, drug and safety standards, are just a few of the objects of public regulations in Canada: M. J. Trebilcock, "The Consumer Interest and Regulatory Reform", in G. B. Doern, ed., *The Regulatory Process in Canada* (1978), 94. Discretion is central to the regulatory agency policy process, but thi discretion will vary from one administrative body to another (see C. L. Brown-John, *Canadian Regulatory Agencies: Quis custodiet ipsos custodes?* (1981), at p. 29). More importantly, in exercising this discretion, statutory bodies must respect the confines of their jurisdiction: they cannot trespass in areas where the legislature has not assigned them authority (see D. J. Mullan, *Administrative Law* (2001), at pp. 9-10).

3 The business of energy and utilities is no exception to this regulatory framework. The respondent in this case is a public utility in Alberta which delivers natural gas. This public utility is nothing more than a private corporation subject to certain regulatory constraints. Fundamentally, it is like any other privately held company: it obtains the necessary funding from investors through public issues of shares in stock and bond markets; it is the [page151] sole owner of the resources, land and other assets; it constructs plants, purchases equipment, and contracts with employees to provide the services; it realizes profits resulting from the application of the rates approved by the Alberta Energy and Utilities Board ("Board") (see P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 *Energy L.J.* 233, at p. 234). That said, one cannot ignore the important feature which makes a public utility so distinct: it must answer to a regulator. Public utilities are typically natural monopolies: technology and demand are such that fixed costs are lower for a single firm to supply the market than would be the case where there is duplication of services by different companies in a competitive environment (see A. E. Kahn, *The Economics of Regulation: Principles and Institutions* (1988), vol. 1, at p. 11; B. W. F. Depoorter, "Regulation of Natural Monopoly", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 498; J. S. Netz, "Price Regulation: A (Non-Technical) Overview", in B. Bouckaert and G. De Geest, eds., *Encyclopedia of Law and Economics* (2000), vol. III, 396, at p. 398; A. J. Black, "Responsible Regulation: Incentive Rates for Natural Gas Pipelines" (1992), 28 *Tulsa L.J.* 349, at p. 351). Efficiency of production is promoted under this model. However, governments have purported to move away from this theoretical concept and have adopted what can only be described as a "regulated monopoly". The utility regulations exist to protect the public from monopolistic behaviour and the consequent inelasticity of demand while ensuring the continued quality of an essential service (see Kahn, at p. 11).

4 As in any business venture, public utilities make business decisions, their ultimate goal being to maximize the residual benefits to shareholders. However, the regulator limits the utility's managerial discretion over key decisions, including prices, service offerings and the prudency of plant and equipment investment decisions. And more relevant to this case, the utility, outside the ordinary course of business, is limited in its right to sell [page152] assets it owns: it must obtain authorization from its regulator before selling an asset previously used to produce regulated services (see MacAvoy and Sidak, at p. 234).

5 Against this backdrop, the Court is being asked to determine whether the Board has jurisdiction pursuant to its enabling statutes to allocate a portion of the net gain on the sale of a now discarded utility asset to the rate-paying customers of the utility when approving the sale. Subsequently, if this first question is answered affirmatively, the Court must consider whether the Board's exercise of its jurisdiction was reasonable and within the limits of its jurisdiction: was it allowed, in the circumstances of this case, to allocate a portion of the net gain on the sale of the utility to the rate-paying customers?

6 The customers' interests are represented in this case by the City of Calgary ("City") which argues that the Board can determine how to allocate the proceeds pursuant to its power to approve the sale and protect the public interest. I find this position unconvincing.

7 The interpretation of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), the *Public Utilities Board Act*, R.S.A. 2000, c. P-45 ("PUBA"), and the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA") (see Appendix for the relevant provisions of these three statutes), can lead to only one conclusion: the Board does not have the prerogative to decide on the distribution of the net gain from the sale of assets of a utility. The Board's seemingly broad powers to make any order and to impose any additional conditions that are necessary in the public interest has to be interpreted within the entire context of the statutes which are meant to balance the need to protect consumers as well as the property rights retained by owners, as recognized in a free market economy. The limits of the powers of the Board are grounded in its main function of fixing just and reasonable rates ("rate setting") and in protecting the integrity and dependability of the supply system.

[page153]

1.1 *Overview of the Facts*

8 ATCO Gas - South ("AGS"), which is a division of ATCO Gas and Pipelines Ltd. ("ATCO"), filed an application by letter with the Board pursuant to s. 25.1(2) (now s. 26(2)) of the GUA, for approval of the sale of its properties located in Calgary known as Calgary Stores Block (the "property"). The property consisted of land and buildings; however, the main value was in the land, and the purchaser intended to and did eventually demolish the buildings and redevelop the land. According to AGS, the property was no longer used or useful for the provision of utility services, and the sale would not cause any harm to customers. In fact, AGS suggested that the sale would result in cost savings to customers, by allowing the net book value of the property to be retired and withdrawn from the rate base, thereby reducing rates. ATCO requested that the Board approve the sale transaction and the disposition of the sale proceeds to retire the remaining book value of the sold assets, to recover the disposition costs, and to recognize the balance of the profits resulting from the sale of the plant should be paid to shareholders. The Board dealt with the application in writing, without witnesses or an oral hearing. Other parties making written submissions to the Board were the City of Calgary, the Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and the Municipal Interveners , who all opposed ATCO's position with respect to the disposition of the sale proceeds to shareholders.

1.2 *Judicial History*

1.2.1 Alberta Energy and Utilities Board

1.2.1.1 *Decision 2001-78*

9 In a first decision, which considered ATCO's application to approve the sale of the property, the Board employed a "no-harm" test, assessing the potential impact on both rates and the level of service to customers and the prudence of the sale transaction, taking into account the purchaser and tender or sale process followed . The Board was of the view that the test had been satisfied. It was [page154] persuaded that customers would not be harmed by the sale, given that a prudent lease arrangement to replace the sold facility had been concluded. The Board was satisfied that there would not be a negative impact on customers' rates, at least during the five-year initial term of the lease. In fact, the Board concluded that there would be cost savings to the customers and that there would be no impact on the level of service to customers as a result of the sale. It did not make a finding on the specific impact on future operating costs; for example, it did not consider the costs of the lease arrangement entered into by ATCO. The Board noted that those costs could be reviewed by the Board in a future general rate application brought by interested parties.

1.2.1.2 *Decision 2002-037, [2002] A.E.U.B.D. No. 52 (QL)*

10 In a second decision, the Board determined the allocation of net sale proceeds. It reviewed the regulatory policy and general principles which affected the decision, although no specific matters are enumerated for consideration in the applicable legislative provisions. The Board had previously developed a "no-harm" test, and it reviewed the rationale for the test as summarized in its Decision 2001-65 (*Re ATCO Gas-North*): "The Board considers that its power to mitigate or offset potential harm to customers by allocating part or all of the sale proceeds to them, flows from its very broad mandate to protect consumers in the public interest" (p. 16).

11 The Board went on to discuss the implications of the Alberta Court of Appeal decision in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171, referring to various decisions it had rendered in the past. Quoting from its Decision 2000-41 (*Re TransAlta Utilities Corp.*), the Board summarized the "*TransAlta Formula*":

> In subsequent decisions, the Board has interpreted the Court of Appeal's conclusion to mean that where the sale price exceeds the original cost of the assets, shareholders are entitled to net book value (in historical dollars), customers are entitled to the difference between [page155] net book value and original cost, and any appreciation in the value of the assets (i.e. the difference between original cost and the sale price) is to be shared by shareholders and customers. The amount to be shared by each is determined by multiplying the ratio of sale price/original cost to the net book value (for shareholders) and the difference between original cost and net book value (for customers). However, where the sale price does not exceed original cost, customers are entitled to all of the gain on sale. [para. 27]

The Board also referred to Decision 2001-65, where it had clarified the following:

> In the Board's view, if the TransAlta Formula yields a result greater than the no-harm amount, customers are entitled to the greater amount. If the TransAlta Formula yields a result less than the no-harm amount, customers are entitled to the no-harm amount. In the Board's view, this approach is consistent with its historical application of the TransAlta Formula. [para. 28]

12 On the issue of its jurisdiction to allocate the net proceeds of a sale, the Board in the present case stated:

> The fact that a regulated utility must seek Board approval before disposing of its assets is sufficient indication of the limitations placed by the legislature on the property rights of a utility. In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.
>
> Regarding AGS's argument that allocating more than the no-harm amount to customers would amount to retrospective ratemaking, the Board again notes the decision in the TransAlta Appeal. The Court of Appeal accepted that the Board could include in the definition of "revenue" an amount payable to customers representing excess depreciation paid by them through past rates. In the Board's view, no question of retrospective ratemaking arises in cases where previously regulated rate base assets are being disposed of out of rate base and the Board applies the TransAlta Formula.
>
> [page156]
>
> The Board is not persuaded by the Company's argument that the Stores Block assets are now 'non-utility' by virtue of being 'no longer required for utility service'. The Board notes that the assets could still be providing service to regulated customers. In fact, the services formerly provided by the Stores Block assets continue to be required, but will be provided from existing and newly leased facilities. Furthermore, the Board notes that even when an asset and the associated service it was providing to

> customers is no longer required the Board has previously allocated more than the no-harm amount to customers where proceeds have exceeded the original cost of the asset. [paras. 47-49]

13 The Board went on to apply the no-harm test to the present facts. It noted that in its decision on the application for the approval of the sale, it had already considered the no-harm test to be satisfied. However, in that first decision, it had not made a finding with respect to the specific impact on future operating costs, including the particular lease arrangement being entered into by ATCO.

14 The Board then reviewed the submissions with respect to the allocation of the net gain and rejected the submission that if the new owner had no use of the buildings on the land, this should affect the allocation of net proceeds. The Board held that the buildings did have some present value but did not find it necessary to fix a specific value. The Board recognized and confirmed that the *TransAlta Formula* was one whereby the "windfall" realized when the proceeds of sale exceed the original cost could be shared between customers and shareholders. It held that it should apply the formula in this case and that it would consider the gain on the transaction as a whole, not distinguishing between the proceeds allocated to land separately from the proceeds allocated to buildings.

15 With respect to allocation of the gain between customers and shareholders of ATCO, the Board tried to balance the interests of both the customers' desire for safe reliable service at a reasonable cost with the provision of a fair return on the investment made by the company:

[page157]

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred. [paras. 112-13]

16 The Board went on to conclude that the sharing of the net gain on the sale of the land and buildings collectively, in accordance with the *TransAlta Formula*, was equitable in the circumstances of this application and was consistent with past Board decisions.

17 The Board determined that from the gross proceeds of $6,550,000, ATCO should receive $465,000 to cover the cost of disposition ($265,000) and the provision for environmental remediation ($200,000), the shareholders should receive $2,014,690, and $4,070,310 should go to the customers. Of the amount credited to shareholders, $225,245 was to be used to remove the remaining net book value of the property from ATCO's accounts. Of the amount allocated to customers, $3,045,813 was allocated to ATCO Gas - South customers and $1,024,497 to ATCO Pipelines - South customers.

1.2.2 Court of Appeal of Alberta ((2004), 24 Alta. L.R. (4th) 205, 2004 ABCA 3)

18 ATCO appealed the Board's decision. It argued that the Board did not have any jurisdiction to allocate the proceeds of sale and that the proceeds should have been allocated entirely to the shareholders. In its view, allowing customers to share in the proceeds of sale would result in them benefiting twice, since they had been spared the costs of renovating the sold assets and would enjoy cost savings from the lease arrangements. The Court of Appeal of Alberta agreed with ATCO, allowing the appeal and setting aside the Board's decision. The [page158] matter was referred back to the Board, and the Board was directed to allocate the entire amount appearing in Line 11 of the allocation of proceeds, entitled "Remainder to be Shared" to ATCO. For the reasons that follow, the Court of Appeal's decision should be upheld, in part; it did not err when it held that the Board did not have the jurisdiction to allocate the proceeds of the sale to ratepayers.

2. Analysis

2.1 *Issues*

19 There is an appeal and a cross-appeal in this case: an appeal by the City in which it submits that, contrary to the Court of Appeal's decision, the Board had jurisdiction to allocate a portion of the net gain on the sale of a utility asset to the rate-paying customers, even where no harm to the public was found at the time the Board approved the sale, and a cross-appeal by ATCO in which it questions the Board's jurisdiction to allocate any of ATCO's proceeds from the sale to customers. In particular, ATCO contends that the Board has no jurisdiction to make an allocation to rate-paying customers, equivalent to the accumulated depreciation calculated for prior years. No matter how the issue is framed, it is evident that the crux of this appeal lies in whether the Board has the jurisdiction to distribute the gain on the sale of a utility company's asset.

20 Given my conclusion on this issue, it is not necessary for me to consider whether the Board's allocation of the proceeds in this case was reasonable. Nevertheless, as I note at para. 82, I will direct my attention briefly to the question of the exercise of discretion in view of my colleague's reasons.

2.2 *Standard of Review*

21 As this appeal stems from an administrative body's decision, it is necessary to determine the appropriate level of deference which must be shown to the body. Wittmann J.A., writing for the Court of Appeal, concluded that the issue of jurisdiction of the Board attracted a standard of correctness. ATCO concurs with this conclusion. I agree. No deference should be shown for the Board's [page159] decision with regard to its jurisdiction on the allocation of the net gain on sale of assets. An inquiry into the factors enunciated by this Court in *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982, confirms this conclusion, as does the reasoning in *United Taxi Drivers' Fellowship of Southern Alberta v. Calgary (City)*, [2004] 1 S.C.R. 485, 2004 SCC 19.

22 Although it is not necessary to conduct a full analysis of the standard of review in this case, I will address the issue briefly in light of the fact that Binnie J. deals with the exercise of discretion in his reasons for judgment. The four factors that need to be canvassed in order to determine the appropriate standard of review of an administrative tribunal decision are: (1) the existence of a privative clause; (2) the expertise of the tribunal/board; (3) the purpose of the governing legislation and the particular provisions; and (4) the nature of the problem (*Pushpanathan*, at paras. 29-38).

23 In the case at bar, one should avoid a hasty characterizing of the issue as "jurisdictional" and subsequently be tempted to skip the pragmatic and functional analysis. A complete examination of the factors is required.

24 First, s. 26(1) of the AEUBA grants a right of appeal, but in a limited way. Appeals are allowed on a question of jurisdiction or law and only after leave to appeal is obtained from a judge:

> **26(1)** Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

[page160]

In addition, the AEUBA includes a privative clause which states that every action, order, ruling or decision of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court (s. 27).

25 The presence of a statutory right of appeal on questions of jurisdiction and law suggests a more searching standard of review and less deference to the Board on those questions (see *Pushpanathan*, at para. 30). However, the presence of the privative clause and right to appeal are not decisive, and one must proceed with the examination of the nature of the question to be determined and the relative expertise of the tribunal in those particular matters.

26 Second, as observed by the Court of Appeal, no one disputes the fact that the Board is a specialized body with a high level of expertise regarding Alberta's energy resources and utilities (see, e.g., *Consumers' Gas Co. v. Ontario (Energy Board)*, [2001] O.J. No. 5024 (QL) (Div. Ct.), at para. 2; *Coalition of Citizens Impacted by the Caroline Shell Plant v. Alberta (Energy Utilities Board)* (1996), 41 Alta. L.R. (3d) 374 (C.A.), at para. 14. In fact, the Board is a permanent tribunal with a long-term regulatory relationship with the regulated utilities.

27 Nevertheless, the Court is concerned not with the general expertise of the administrative decision maker, but with its expertise in relation to the specific nature of the issue before it. Consequently, while normally one would have assumed that the Board's expertise is far greater than that of a court, the nature of the problem at bar, to adopt the language of the Court of Appeal (para. 35), "neutralizes" this deference. As I will elaborate below, the expertise of the Board is not engaged when deciding the scope of its powers.

[page161]

28 Third, the present case is governed by three pieces of legislation: the PUBA, the GUA and the AEUBA. These statutes give the Board a mandate to safeguard the public interest in the nature and quality of the service provided to the community by public utilities: *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576; *Dome Petroleum Ltd. v. Public Utilities Board (Alberta)* (1976), 2 A.R. 453 (C.A.), at paras. 20-22, aff'd [1977] 2 S.C.R. 822. The legislative framework at hand has as its main purpose the proper regulation of a gas utility in the public interest, more specifically the regulation of a monopoly in the public interest with its primary tool being rate setting, as I will explain later.

29 The particular provision at issue, s. 26(2)(d)(i) of the GUA, which requires a utility to obtain the approval of the regulator before it sells an asset, serves to protect the customers from adverse results brought about by any of the utility's transactions by ensuring that the economic benefits to customers are enhanced (MacAvoy and Sidak, at pp. 234-36).

30 While at first blush the purposes of the relevant statutes and of the Board can be conceived as a delicate balancing between different constituencies, i.e., the utility and the customer, and therefore entail determinations which are polycentric (*Pushpanathan*, at para. 36), the interpretation of the enabling statutes and the particular provisions under review (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) is not a polycentric question, contrary to the conclusion of the Court of Appeal. It is an inquiry into whether a proper construction of the enabling statutes gives the Board jurisdiction to allocate the profits realized from the sale of an asset. The Board was not created with the main purpose of interpreting the AEUBA, the GUA or the PUBA in the abstract, where no policy consideration is at issue, but rather to ensure that utility rates are always just and reasonable (see *Atco Ltd.*, at p. 576). In the case at bar, this protective role does not come into play. Hence, this factor points to a less deferential standard of review.

[page162]

31 Fourth, the nature of the problem underlying each issue is different. The parties are in essence asking the Court to answer two questions (as I have set out above), the first of which is to determine whether the power to dispose of the proceeds of sale falls within the Board's statutory mandate. The Board, in its decision, determined that it had the power to allocate a portion of the proceeds of a sale of utility assets to the ratepayers; it based its decision on its statutory powers, the equitable principles rooted in the "regulatory compact" (see para. 63 of these reasons) and previous practice. This question is undoubtedly one of law and jurisdiction. The Board would arguably have no greater expertise with regard to this issue than the courts. A court is called upon to interpret provisions that have no technical aspect, in contrast with the provision disputed in *Barrie Public Utilities v. Canadian Cable Television Assn.*, [2003] 1 S.C.R. 476, 2003 SCC 28, at para. 86. The interpretation of general concepts such as "public interest" and "conditions" (as found in s. 15(3)(d) of the AEUBA) is not foreign to courts and is not derived from an area where the tribunal has been held to have greater expertise than the courts. The second question is whether the method and actual allocation in this case were reasonable. To resolve this issue, one must consider case law, policy justifications and the practice of other boards, as well as the details of the particular allocation in this case. The issue here is most likely characterized as one of mixed fact and law.

32 In light of the four factors, I conclude that each question requires a distinct standard of review. To determine the Board's power to allocate proceeds from a sale of utility assets suggests a standard of review of correctness. As expressed by the Court of Appeal, the focus of this inquiry remains on the particular provisions being invoked and interpreted by the tribunal (s. 26(2)(d) of the GUA and s. 15(3)(d) of the AEUBA) and "goes to jurisdiction" [page163] (*Pushpanathan*, at para. 28). Moreover, keeping in mind all the factors discussed, the generality of the proposition wil be an additional factor in favour of the imposition of a correctness standard, as I stated in *Pushpanathan*, at para. 38:

> ... the broader the propositions asserted, and the further the implications of such decisions stray from the core expertise of the tribunal, the less likelihood that deference will be shown. Without an implied or express legislative intent to the contrary as manifested in the criteria above, legislatures should be assumed to have left highly generalized propositions of law to courts.

33 The second question regarding the Board's actual method used for the allocation of proceeds likely attracts a more deferential standard. On the one hand, the Board's expertise, particularly in this area, its broad mandate, the technical nature of the question and the general purposes of the legislation, all suggest a relatively high level of deference to the Board's decision. On the other hand, the absence of a privative clause on questions of jurisdiction and the reference to law neede to answer this question all suggest a less deferential standard of review which favours reasonableness. It is not necessary, however, for me to determine which specific standard would have applied here.

34 As will be shown in the analysis below, I am of the view that the Court of Appeal made no error of fact or law when it concluded that the Board acted beyond its jurisdiction by misapprehending its statutory and common law authority. However, the Court of Appeal erred when it did not go on to conclude that the Board has no jurisdiction to allocate *any* portion of the proceeds of sale of the property to ratepayers.

2.3 *Was the Board's Decision as to Its Jurisdiction Correct?*

35 Administrative tribunals or agencies are statutory creations: they cannot exceed the powers that were granted to them by their enabling statute; they [page164] must "adhere to the confines of their statutory authority or 'jurisdiction'[; and t]hey cannot trespass in areas where the legislature has not assigned them authority": Mullan, at pp. 9-10 (see also S. Blake, *Administrative Law in Canada* (3rd ed. 2001), at pp. 183-84).

36 In order to determine whether the Board's decision that it had the jurisdiction to allocate proceeds from the sale of a utility's asset was correct, I am required to interpret the legislative framework by which the Board derives its powers and actions.

2.3.1 General Principles of Statutory Interpretation

37 For a number of years now, the Court has adopted E. A. Driedger's modern approach as the method to follow for statutory interpretation (*Construction of Statutes* (2nd ed. 1983), at p. 87):

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

(See, e.g., *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, at para. 21; *Bell ExpressVu Limited Partnership v. Rex*, [2002] 2 S.C.R. 559, 2002 SCC 42, at para. 26; *H.L. v. Canada (Attorney General)*, [2005] 1 S.C.R. 401, 2005 SCC 25, at paras. 186-87; *Marche v. Halifax Insurance Co.*, [2005] 1 S.C.R. 47, 2005 SCC 6, at para. 54; *Barrie Public Utilities*, at paras. 20 and 86; *Contino v. Leonelli-Contino*, [2005] 3 S.C.R. 217, 2005 SCC 63, at para. 19.)

38 But more specifically in the area of administrative law, tribunals and boards obtain their jurisdiction over matters from two sources: (1) express grants of jurisdiction under various statutes (explicit powers); and (2) the common law, by application of the doctrine of jurisdiction by necessary implication (implicit powers) (see also D. M. Brown, *Energy Regulation in Ontario* (loose-leaf ed.), at p. 2-15).

39 The City submits that it is both implicit and explicit within the express jurisdiction [page165] that has been conferred upon the Board to approve or refuse to approve the sale of utility assets, that the Board can determine how to allocate the proceeds of the sale in this case. ATCO retorts that not only is such a power absent from the explicit language of the legislation, but it cannot be "implied" from the statutory regime as necessarily incidental to the explicit powers. I agree with ATCO's submissions and will elaborate in this regard.

2.3.2 Explicit Powers: Grammatical and Ordinary Meaning

40 As a preliminary submission, the City argues that given that ATCO applied to the Board for approval of both the sale transaction *and* the disposition of the proceeds of sale, this suggests that ATCO recognized that the Board has authority to allocate the proceeds as a condition of a proposed sale. This argument does not hold any weight in my view. First, the application for approval cannot be considered on its own an admission by ATCO of the jurisdiction of the Board. In any event, an admission of this nature would not have any bearing on the applicable law. Moreover, knowing that in the past the Board had decided that it had jurisdiction to allocate the proceeds of a sale of assets and had acted on this power, one can assume that ATCO was asking for the approval of the disposition of the proceeds should the Board not accept their argument on jurisdiction. In fact, a review of past Board decisions on the approval of sales shows that utility companies have constantly challenged the Board's jurisdiction to allocate the net gain on the sale of assets (see, e.g., *Re TransAlta Utilities Corp.*, Alta. E.U.B., Decision 2000-41; *Re ATCO Gas-North*, Alta. E.U.B., Decision 2001-65; *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984; *TransAlta Utilities Corp. (Re)*, [2002] A.E.U.B.D. No. 30 (QL); *ATCO Electric Ltd. (Re)*, [2003] A.E.U.B.D. No. 92 (QL)).

41 The starting point of the analysis requires that the Court examine the ordinary meaning of the sections at the centre of the dispute, s. 26(2)(d)(i) of the GUA, ss. 15(1) and 15(3)(d) of the AEUBA and [page166] s. 37 of the PUBA. For ease of reference, I reproduce these provisions:

GUA

26. ...

(2) No owner of a gas utility designated under subsection (1) shall

...

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them

...

and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

AEUBA

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB [Energy Resources Conservation Board] and the PUB [Public Utilities Board] that are granted or provided for by any enactment or by law.

...

(3) Without restricting subsection (1), the Board may do all or any of the following:

...

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

...

[page167]

PUBA

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

42 Some of the above provisions are duplicated in the other two statutes (see, e.g., PUBA, ss. 85(1) and 101(2)(d)(i) ; GUA, s. 22(1) ; see Appendix).

43 There is no dispute that s. 26(2) of the GUA contains a prohibition against, among other things, the owner of a utility selling, leasing, mortgaging or otherwise disposing of its property outside of the ordinary course of business without the approval of the Board. As submitted by ATCO, the power conferred is to approve without more. There is no mention in s. 26 of the grounds for granting or denying approval or of the ability to grant conditional approval, let alone the power of the Board to allocate the net profit of an asset sale. I would note in passing that this power is sufficient to alleviate the fear expressed by the Board that the utility might be tempted to sell assets on which it might realize a large profit to the detriment of ratepayers if it could reap the benefits of the sale.

44 It is interesting to note that s. 26(2) does not apply to all types of sales (and leases, mortgages, dispositions, encumbrances, mergers or consolidations). It excludes sales in the ordinary course of the owner's business. If the statutory scheme was such that the Board had the power to allocate the proceeds of the sale of utility assets, as argued here, s. 26(2) would naturally apply to all sales of assets or, at a minimum, exempt only those sales below a certain value. It is apparent that allocation of sale proceeds to customers is not one of its purposes. In fact, s. 26(2) can only have limited, if any, application to non-utility assets not related to utility function (especially when the sale has passed the "no-harm" [page168] test). The provision can only be meant to ensure that the asset in question is indeed non-utility, so that its loss does not impair the utility function or quality.

45 Therefore, a simple reading of s. 26(2) of the GUA does permit one to conclude that the Board does not have the power to allocate the proceeds of an asset sale.

46 The City does not limit its arguments to s. 26(2); it also submits that the AEUBA, pursuant to s. 15(3), is an express grant of jurisdiction because it authorizes the Board to impose any condition to any order so long as the condition is necessary in the public interest. In addition, it relies on the general power in s. 37 of the PUBA for the proposition that the Board may, in any matter within its jurisdiction, make any order pertaining to that matter that is not inconsistent with any applicable statute. The intended meaning of these two provisions, however, is lost when the provisions are simply read in isolation as proposed by the City: R. Sullivan, *Sullivan and Driedger on the Construction of Statutes* (4th ed. 2002), at p. 21; *Canadian Pacific Air Lines Ltd. v. Canadian Air Line Pilots Assn.*, [1993] 3 S.C.R. 724, at p. 735; *Marche*, at paras. 59-60; *Bristol-Myers Squibb Co. v. Canada (Attorney General)*, [2005] 1 S.C.R. 533, 2005 SCC 26, at para. 105. These provisions on their own are vague and open-ended. It would be absurd to allow the Board an unfettered discretion to attach any condition it wishes to an order it makes. Furthermore, the concept of "public interest" found in s. 15(3) is very wide and elastic; the Board cannot be given total discretion over its limitations.

47 While I would conclude that the legislation is silent as to the Board's power to deal with sale [page169] proceeds after the initial stage in the statutory interpretation analysis, because the provisions can nevertheless be said to reveal some ambiguity and incoherence, I will pursue the inquiry further.

48 This Court has stated on numerous occasions that the grammatical and ordinary sense of a section is not determinative and does not constitute the end of the inquiry. The Court is obliged to consider the total context of the provisions to be interpreted, no matter how plain the disposition may seem upon initial reading (see *Chieu v. Canada (Minister of Citizenship and Immigration)*, [2002] 1 S.C.R. 84, 2002 SCC 3, at para. 34; Sullivan, at pp. 20-21). I will therefore proceed to examine the purpose and scheme of the legislation, the legislative intent and the relevant legal norms.

2.3.3 Implicit Powers: Entire Context

49 The provisions at issue are found in statutes which are themselves components of a larger statutory scheme which cannot be ignored:

> As the product of a rational and logical legislature, the statute is considered to form a system. Every component contributes to the meaning as a whole, and the whole gives meaning to its parts: "each legal provision should be considered in relation to other provisions, as parts of a whole" ... .
>
> (P.-A. Côté, *The Interpretation of Legislation in Canada* (3rd ed. 2000), at p. 308)

As in any statutory interpretation exercise, when determining the powers of an administrative body, courts need to examine the context that colours the words and the legislative scheme. The ultimate goal is to discover the clear intent of the legislature and the true purpose of the statute while preserving the harmony, coherence and consistency of the legislative scheme (*Bell ExpressVu*, at para. 27; see also *Interpretation Act*, R.S.A. 2000, c. I-8, s. 10 (in Appendix)). "[S] tatutory interpretation is the art of finding the legislative spirit embodied in enactments": *Bristol-Myers Squibb Co.*, at para. 102.

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50 Consequently, a grant of authority to exercise a discretion as found in s. 15(3) of the AEUBA and s. 37 of the PUBA does not confer unlimited discretion to the Board. As submitted by ATCO, the Board's discretion is to be exercised 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 (see Sullivan, at pp. 154-55). In the same vein, it is useful to refer to the following passage from *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722, at p. 1756:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the wording of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

51 The mandate of this Court is to determine and apply the intention of the legislature (*Bell ExpressVu*, at para. 62) without crossing the line between judicial interpretation and legislative drafting (see *R. v. McIntosh*, [1995] 1 S.C.R. 686, at para. 26; *Bristol-Myers Squibb Co.*, at para. 174). That being said, this rule allows for the application of the "doctrine of jurisdiction by necessary implication"; the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature (see Brown, at p. 2-16.2; *Bell Canada*, at p. 1756). Canadian courts have in the past applied the doctrine to ensure that administrative bodies have the necessary jurisdiction to accomplish their statutory mandate:

> When legislation attempts to create a comprehensive regulatory framework, the tribunal must have the powers which by practical necessity and necessary implication flow from the regulatory authority explicitly conferred upon it.

[page171]

Re Dow Chemical Canada Inc. and Union Gas Ltd. (1982), 141 D.L.R. (3d) 641 (Ont. H.C.), at pp. 658-59, aff'd (1983), 42 O.R. (2d) 731 (C.A.) (see also *Interprovincial Pipe Line Ltd. v. National Energy Board*, [1978] 1 F.C. 601 (C.A.); *Canadian Broadcasting League v. Canadian Radio-television and Telecommunications Commission*, [1983] 1 F.C. 182 (C.A.), aff'd [1985] 1 S.C.R. 174).

52 I understand the City's arguments to be as follows : (1) the customers acquire a right to the property of the owner of the utility when they pay for the service and are therefore entitled to a return on the profits made at the time of the sale of the property; and (2) the Board has, by necessity, because of its jurisdiction to approve or refuse to approve the sale of utility assets, the power to allocate the proceeds of the sale as a condition of its order. The doctrine of jurisdiction by necessary implication is at the heart of the City's second argument. I cannot accept either of these arguments which are, in my view, diametrically contrary to the state of the law. This is revealed when we scrutinize the entire context which I will now endeavour to do.

53 After a brief review of a few historical facts, I will probe into the main function of the Board, rate setting, and I will then explore the incidental powers which can be derived from the context.

2.3.3.1 *Historical Background and Broader Context*

54 The history of public utilities regulation in Alberta originated with the creation in 1915 of the Board of Public Utility Commissioners by *The Public Utilities Act*, S.A. 1915, c. 6. This statute was based on similar American legislation: H. R. Milner, "Public Utility Rate Control in Alberta" (1930), 8 *Can. Bar Rev.* 101, at p. 101. While the American jurisprudence and texts in this area should be considered with caution given that Canada and the United States have very different political and constitutional-legal regimes, they do shed some light on the issue.

55 Pursuant to *The Public Utilities Act*, the first public utility board was established as a [page172] three-member tribunal to provide general supervision of all public utilities (s. 21), to investigate rates (s. 23), to make orders regarding equipment (s. 24), and to require every public utility to file with it complete schedules of rates (s. 23). Of interest for our purposes, the 1915 statute also required public utilities to obtain the approval of the Board of Public Utility Commissioners before selling any property when outside the ordinary course of their business (s. 29(g)).

56 The Alberta Energy and Utilities Board was created in February 1995 by the amalgamation of the Energy Resources Conservation Board and the Public Utilities Board (see Canadian Institute of Resources Law, *Canada Energy Law Service: Alberta* (loose-leaf ed.), at p. 30-3101). Since then, all matters under the jurisdiction of the Energy Resources Conservation Board and the Public Utilities Board have been handled by the Alberta Energy and Utilities Board and are within its exclusive jurisdiction. The Board has all of the powers, rights and privileges of its two predecessor boards (AEUBA, ss. 13, 15(1); GUA, s. 59).

57 In addition to the powers found in the 1915 statute, which have remained virtually the same in the present PUBA , the Board now benefits from the following express powers to:

1. make an order respecting the improvement of the service or commodity (PUBA, s. 80(b));
2. approve the issue by the public utility of shares, stocks, bonds and other evidences of indebtedness (GUA, s. 26(2)(a); PUBA, s. 101(2)(a));
3. approve the lease, mortgage, disposition or encumbrance of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(i); PUBA, s. 101(2)(d)(i));
4. approve the merger or consolidation of the public utility's property, franchises, privileges or rights (GUA, s. 26(2)(d)(ii); PUBA, s. 101(2)(d)(ii)); and

[page173]

5. authorize the sale or permit to be made on the public utility's book a transfer of any share of its capital stock to a corporation that would result in the vesting in that corporation of more than 50 percent of the outstanding capital stock of the owner of the public utility (GUA, s. 27(1); PUBA, s. 102(1)).

58 It goes without saying that public utilities are very limited in the actions they can take, as evidenced from the above list. Nowhere is there a mention of the authority to allocate proceeds from a sale or the discretion of the Board to interfere with ownership rights.

59 Even in 1995 when the legislature decided to form the Alberta Energy and Utilities Board, it did not see fit to modify the PUBA or the GUA to provide the new Board with the power to allocate the proceeds of a sale even though the controversy surrounding this issue was full-blown (see, e.g., *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116). It is a well-established principle that the legislature is presumed to have a mastery of existing law, both common law and statute law (see Sullivan, at pp. 154-55). It is also presumed to have known all of the circumstances surrounding the adoption of new legislation.

60 Although the Board may seem to possess a variety of powers and functions, it is manifest from a reading of the AEUBA, the PUBA and the GUA that the principal function of the Board in respect of public utilities is the determination of rates. Its power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates (see Milner, at p. 102; Brown, at p. 2-16.6). Estey J., speaking for the majority of this Court in *Atco Ltd.*, at p. 576, echoed this view when he said:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the [page174] community by the public utilities. Such an extensive regulatory pattern must, for its effectiveness, include the right to control the combination or, as the legislature says, "the union" of existing systems and facilities. <u>This no doubt has a direct relationship with the rate-fixing function which ranks high in the authority and functions assigned to the Board.</u> [Emphasis added.]

In fact, even the Board itself, on its website (http://www.eub.gov.ab.ca/BBS/eubinfo/default.htm), describes its functions as follows:

> We regulate the safe, responsible, and efficient development of Alberta's energy resources: oil, natural gas, oil sands, coal, and electrical energy; and the pipelines and transmission lines to move the resources to market. On the utilities side, we regulate rates and terms of service of investor-owned natural gas, electric, and water utility services, as well as the major intra-Alberta gas transmission system, to ensure that customers receive safe and reliable service at just and reasonable rates. [Emphasis added.]

61 The process by which the Board sets the rates is therefore central and deserves some attention in order to ascertain the validity of the City's first argument.

2.3.3.2 *Rate Setting*

62 Rate regulation serves several aims -- sustainability, equity and efficiency -- which underlie the reasoning as to how rates are fixed:

> ... the regulated company must be able to finance its operations, and any required investment, so that it can continue to operate in the future... . Equity is related to the distribution of welfare among members of society. The objective of sustainability already implies that shareholders should not receive "too low" a return (and defines this in terms of the reward necessary to ensure continued investment in the utility), while equity implies that their returns should not be "too high".
>
> (R. Green and M. Rodriguez Pardina, *Resetting Price Controls for Privatized Utilities: A Manual for Regulators* (1999), at p. 5)

63 These goals have resulted in an economic and social arrangement dubbed the "regulatory [page175] compact" which ensures that all customers have access to the utility at a fair price -- nothing more. As I will further explain, it does not transfer onto the customers any property right. Under the regulatory compact, the regulated utilities are given exclusive rights to sell their services within a specific area at rates that will provide companies the opportunity to earn a fair return for their investors. In return for this right of exclusivity, utilities assume a duty to adequately and reliably serve all customers in their determined territories, and are required to have their rates and certain operations regulated (see Black, at pp. 356-57; Milner, at p. 101; *Atco Ltd.*, at p. 576; *Northwestern Utilities Ltd. v. City of Edmonton*, [1929] S.C.R. 186 ("*Northwestern 1929*"), at pp. 192-93).

64 Therefore, when interpreting the broad powers of the Board, one cannot ignore this well-balanced regulatory arrangement which serves as a backdrop for contextual interpretation. The object of the statutes is to protect both the customer *and* the investor (Milner, at p. 101). The arrangement does not, however, cancel the private nature of the utility. In essence, the Board is responsible for maintaining a tariff that enhances the economic benefits to consumers and investors of the utility.

65 The Board derives its power to set rates from both the GUA (ss. 16, 17 and 36 to 45) and the PUBA (ss. 89 to 95). The Board is mandated to fix "just and reasonable ... rates" (PUBA, s. 89 (a); GUA, s. 36(a)). In the establishment of these rates, the Board is directed to "determine a rate base for the property of the owner" and "fix a fair return on the rate base" (GUA, s. 37(1)). This Court, in *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684 ("*Northwestern 1979*"), at p. 691, adopted the following description of the process:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money

> which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to [page176] provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

(See also *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984, at p. 23; *Re Union Gas Ltd. and Ontario Energy Board* (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.), at pp. 701-2.)

66 Consequently, when determining the rate base, the Board is to give due consideration (GUA, s. 37(2)):

> (a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> (b) to necessary working capital.

67 The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. In fact, the wording of the sections quoted above suggests that the ownership of the assets is clearly that of the utility; ownership of the asset and entitlement to profits or losses upon its realization are one and the same. The equity investor expects to receive the net revenues after all costs are paid, equal to the present value of original investment at the time of that investment. The disbursement of some portions of the residual amount of net revenue, by after-the-fact reallocation to rate-paying customers, undermines that investment process: [page177] MacAvoy and Sidak, at p. 244. In fact, speculation would accrue even more often should the public utility, through its shareholders, not be the one to benefit from the possibility of a profit, as investors would expect to receive a larger premium for their funds through the only means left available, the return on their original investment. In addition, they would be less willing to accept any risk.

68 Thus, can it be said, as alleged by the City, that the customers have a property interest in the utility? Absolutely not: that cannot be so, as it would mean that fundamental principles of corporate law would be distorted. Through the rates, the customers pay an amount for the regulated service that equals the cost of the service and the necessary resources. They do not by their payment implicitly purchase the asset from the utility's investors. The payment does not incorporate acquiring ownership or control of the utility's assets. The ratepayer covers the cost of using the service, not the holding cost of the assets themselves: "A utility's customers are not its owners, for they are not residual claimants": MacAvoy and Sidak, at p. 245 (see also p. 237). Ratepayers have made no investment. Shareholders have and they assume all risks as the residual claimants to the utility's profit. Customers have only "the risk of a price change resulting from any (authorized) change in the cost of service. This change is determined only periodically in a tariff review by the regulator" (MacAvoy and Sidak, at p. 245).

69 In this regard, I agree with ATCO when it asserts in its factum, at para. 38:

> The property in question is as fully the private property of the owner of the utility as any other asset it owns. Deployment of the asset in utility service does not create or

> transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory ... .

Wittmann J.A., at the Court of Appeal, said it best when he stated:

> Consumers of utilities pay for a service, but by such payment, do not receive a proprietary right in the [page178] assets of the utility company. Where the calculated rates represent the fee for the service provided in the relevant period of time, ratepayers do not gain equitable or legal rights to non-depreciable assets when they have paid only for the use of those assets. [Emphasis added; para. 64.]

I fully adopt this conclusion. The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. While the utility has been compensated for the services provided, the customers have provided no compensation for receiving the benefits of the subject property. The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases and decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide certainty in service both with regard to price and quality. There can be a default risk affecting ratepayers, but this does not make ratepayers residual claimants. While I do not wish to unduly rely on American jurisprudence, I would note that the leading U.S. case on this point is *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989), which relies on the same principle as was adopted in *Market St. Ry. Co. v. Railroad Commission of State of California*, 324 U.S. 548 (1945).

70 Furthermore, one has to recognize that utilities are not Crown entities, fraternal societies or cooperatives, or mutual companies, although they have a "public interest" aspect which is to supply the public with a necessary service (in the present case, [page179] the provision of natural gas). The capital invested is not provided by the public purse or by the customers; it is injected into the business by private parties who expect as large a return on the capital invested in the enterprise as they would receive if they were investing in other securities possessing equal features of attractiveness, stability and certainty (see *Northwestern 1929*, at p. 192). This prospect will necessarily include any gain or loss that is made if the company divests itself of some of its assets, i.e., land, buildings, etc.

71 From my discussion above regarding the property interest, the Board was in no position to proceed with an implicit refund by allocating to ratepayers the profits from the asset sale because it considered ratepayers had paid excessive rates for services in the past. As such, the City's first argument must fail. The Board was seeking to rectify what it perceived as a historic over-compensation to the utility by ratepayers. There is no power granted in the various statutes for the Board to execute such a refund in respect of an erroneous perception of past over-compensation. It is well established throughout the various provinces that utilities boards do not have the authority to retroactively change rates (*Northwestern 1979*, at p. 691; *Re Coseka Resources Ltd. and Saratoga Processing Co.* (1981), 126 D.L.R. (3d) 705 (Alta. C.A.), at p. 715, leave to appeal refused, [1981] 2 S.C.R. vii; *Re Dow Chemical Canada Inc.* (C.A.), at pp. 734-35). But more importantly, it cannot even be said that there was over-compensation: the rate-setting process is a speculative procedure in which both the ratepayers and the shareholders jointly carry their share of the risk related to the business of the utility (see MacAvoy and Sidak, at pp. 238-39).

2.3.3.3 *The Power to Attach Conditions*

72 As its second argument, the City submits that the power to allocate the proceeds from the sale of the utility's assets is necessarily incidental to the express powers conferred on the Board by the AEUBA, the GUA and the PUBA. It argues that the Board must necessarily have the power to allocate sale proceeds as part of its discretionary power to approve or refuse to approve a sale of assets. It [page180] submits that this results from the fact that the Board is allowed to attach any condition to an order it makes approving such a sale. I disagree.

73 The City seems to assume that the doctrine of jurisdiction by necessary implication applies to "broadly drawn powers" as it does for "narrowly drawn powers"; this cannot be. The Ontario Energy Board in its decision in *Re Consumers' Gas Co.*, E.B.R.O. 410-II/411-II/412-II, March 23, 1987, at para. 4.73, enumerated the circumstances when the doctrine of jurisdiction by necessary implication may be applied:

> * [when] the jurisdiction sought is necessary to accomplish the objectives of the legislative scheme and is essential to the Board fulfilling its mandate;
> * [when] the enabling act fails to explicitly grant the power to accomplish the legislative objective;
> * [when] the mandate of the Board is sufficiently broad to suggest a legislative intention to implicitly confer jurisdiction;
> * [when] 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
> * [when] the Legislature did not address its mind to the issue and decide against conferring the power upon the Board.

(See also Brown, at p. 2-16.3.)

74 In light of the above, it is clear that the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework. This is explained by Professor Sullivan, at p. 228:

> In practice, however, purposive analysis makes the powers conferred on administrative bodies almost infinitely elastic. <u>Narrowly drawn powers can be understood to include "by necessary implication" all that is needed to enable the official or agency to achieve the [page181] purpose for which the power was granted. Conversely, broadly drawn powers are understood to include only what is rationally related to the purpose of the power.</u> In this way the scope of the power expands or contracts as needed, in keeping with the purpose. [Emphasis added.]

75 In the case at bar, s. 15 of the AEUBA, which allows the Board to impose additional conditions when making an order, appears at first glance to be a power having infinitely elastic scope. However, in my opinion, the attempt by the City to use it to augment the powers of the Board in s. 26(2) of the GUA must fail. The Court must construe s. 15(3) of the AEUBA in accordance with the purpose of s. 26(2).

76 MacAvoy and Sidak, in their article, at pp. 234-36, suggest three broad reasons for the requirement that a sale must be approved by the Board:

> 1. It prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers;
> 2. It ensures that the utility maximizes the aggregate economic benefits of its

operations, and not merely the benefits flowing to some interest group or stakeholder; and

3. It specifically seeks to prevent favoritism toward investors.

77 Consequently, in order to impute jurisdiction to a regulatory body to allocate proceeds of a sale, there must be evidence that the exercise of that power is a practical necessity for the regulatory body to accomplish the objects prescribed by the legislature, something which is absent in this case (see *National Energy Board Act (Can.) (Re)*, [1986] 3 F.C. 275 (C.A.)). In order to meet these three goals, it is not necessary for the Board to have control over which party should benefit from the sale proceeds. The public interest component cannot be said to be sufficient to impute to the Board the power to allocate all the profits pursuant to the sale of assets. In fact, it is not necessary for the Board in [page182] carrying out its mandate to order the utility to surrender the bulk of the proceeds from a sale of its property in order for that utility to obtain approval for a sale. The Board has other options within its jurisdiction which do not involve the appropriation of the sale proceeds, the most obvious one being to refuse to approve a sale that will, in the Board's view, affect the quality and/or quantity of the service offered by the utility or create additional operating costs for the future. This is not to say that the Board can never attach a condition to the approval of sale. For example, the Board could approve the sale of the assets on the condition that the utility company gives undertakings regarding the replacement of the assets and their profitability. It could also require as a condition that the utility reinvest part of the sale proceeds back into the company in order to maintain a modern operating system that achieves the optimal growth of the system.

78 In my view, allowing the Board to confiscate the net gain of the sale under the pretence of protecting rate-paying customers and acting in the "public interest" would be a serious misconception of the powers of the Board to approve a sale; to do so would completely disregard the economic rationale of rate setting, as I explained earlier in these reasons. Such an attempt by the Board to appropriate a utility's excess net revenues for ratepayers would be highly sophisticated opportunism and would, in the end, simply increase the utility's capital costs (MacAvoy and Sidak, at p. 246). At the risk of repeating myself, a public utility is first and foremost a private business venture which has as its goal the making of profits. This is not contrary to the legislative scheme, even though the regulatory compact modifies the normal principles of economics with various restrictions explicitly provided for in the various enabling statutes. None of the three statutes applicable here provides the Board with the power to allocate the proceeds of a sale and therefore affect the property interests of the public utility.

79 It is well established that potentially confiscatory legislative provision ought to be construed cautiously so as not to strip interested parties of their rights without the clear intention of the [page183] legislation (see Sullivan, at pp. 400-403; Côté, at pp. 482-86; *Pacific National Investments Ltd. v. Victoria (City)*, [2000] 2 S.C.R. 919, 2000 SCC 64, at para. 26; *Leiriao v. Val-Bélair (Town)*, [1991] 3 S.C.R. 349, at p. 357; *Hongkong Bank of Canada v. Wheeler Holdings Ltd.*, [1993] 1 S.C.R. 167, at p. 197). Not only is the authority to attach a condition to allocate the proceeds of a sale to a particular party unnecessary for the Board to accomplish its role, but deciding otherwise would lead to the conclusion that a broadly drawn power can be interpreted so as to encroach on the economic freedom of the utility, depriving it of its rights. This would go against the above principles of interpretation.

80 If the Alberta legislature wishes to confer on ratepayers the economic benefits resulting from the sale of utility assets, it can expressly provide for this in the legislation, as was done by some states in the United States (e.g., Connecticut).

2.4 *Other Considerations*

81 Under the regulatory compact, customers are protected through the rate-setting process, under which the Board is required to make a well-balanced determination. The record shows that the City did not submit to the Board a general rate review application in response to ATCO's application requesting approval for the sale of the property at issue in this case. Nonetheless, if it chose to do so, this would not have stopped the Board, on its own initiative, from convening a hearing of the interested parties in order to modify and fix just and reasonable rates to give due consideration to any new economic data anticipated as a result of the sale (PUBA, s. 89(a); GUA, ss. 24, 36(a), 37(3), 40) (see Appendix).

2.5 *If Jurisdiction Had Been Found, Was the Board's Allocation Reasonable?*

82 In light of my conclusion with regard to jurisdiction, it is not necessary to determine whether [page184] the Board's exercise of discretion by allocating the sale proceeds as it did was reasonable. Nonetheless, given the reasons of my colleague Binnie J., I will address the issue very briefly. Had I not concluded that the Board lacked jurisdiction, my disposition of this case would have been the same, as I do not believe the Board met a reasonable standard when it exercised its power.

83 I am not certain how one could conclude that the Board's allocation was reasonable when it wrongly assumed that ratepayers had acquired a proprietary interest in the utility's assets because assets were a factor in the rate-setting process, and, moreover, when it explicitly concluded that no harm would ensue to customers from the sale of the asset. In my opinion, when reviewing the substance of the Board's decision, a court must conduct a two-step analysis: first, it must determine whether the order was warranted given the role of the Board to *protect the customers* (i.e., was the order *necessary in the public interest*?); and second, if the first question is answered in the affirmative, a court must then examine the validity of the Board's application of the *TransAlta Formula* (see para. 12 of these reasons), which refers to the difference between net book value and original cost, on the one hand, and appreciation in the value of the asset on the other. For the purposes of this analysis, I view the second step as a mathematical calculation and nothing more. I do not believe it provides the criteria which guides the Board to determine *if it should allocate* part of the sale proceeds to ratepayers. Rather, it merely guides the Board on *what to allocate and how to allocate it* (if it should do so in the first place). It is also interesting to note that there is no discussion of the fact that the book value used in the calculation must be referable solely to the financial statements of the utility.

84 In my view, as I have already stated, the power of the Board to allocate proceeds does not even arise in this case. Even by the Board's own reasoning, it should only exercise its discretion to act in the public interest when customers would be harmed [page185] or would face some risk of harm. But the Board was clear: there was no harm or risk of harm in the present situation:

> With the continuation of the same level of service at other locations and the acceptance by customers regarding the relocation, the Board is convinced there should be no impact on the level of service to customers as a result of the Sale. In any event, the Board considers that the service level to customers is a matter that can be addressed and remedied in a future proceeding if necessary.

(Decision 2002-037, at para. 54)

After declaring that the customers would not, on balance, be harmed, the Board maintained that, on the basis of the evidence filed, there appeared to be a cost savings to the customers. There was no legitimate customer interest which could or needed to be protected by denying approval of the sale, or by making approval conditional on a particular allocation of the proceeds. Even if the Board had found a possible adverse effect arising from the sale, how could it allocate proceeds now based on an unquantified future potential loss? Moreover, in the absence of any factual basis to support it, I am also concerned with the presumption of bad faith on the part of ATCO that appears to underlie the Board's determination to protect the public from some possible future menace. In any case, as mentioned earlier in these reasons, this determination to protect the public interest is also difficult to reconcile with the actual power of the Board to prevent harm to ratepayers from occurring by simply refusing to approve the sale of a utility's asset. To that, I would add that the Board has considerable discretion in the setting of future rates in order to protect the public interest, as I have already stated.

85 In consequence, I am of the view that, in the present case, the Board did not identify any public interest which required protection and there was, therefore, nothing to trigger the exercise of the discretion to allocate the proceeds of sale. Hence, notwithstanding my conclusion on the first issue regarding the Board's jurisdiction, I would conclude [page186] that the Board's decision to exercise its discretion to protect the public interest did not meet a reasonable standard.

3. Conclusion

86 This Court's role in this case has been one of interpreting the enabling statutes using the appropriate interpretive tools, i.e., context, legislative intention and objective. Going further than required by reading in *unnecessary* powers of an administrative agency under the guise of statutory interpretation is not consistent with the rules of statutory interpretation. It is particularly dangerous to adopt such an approach when property rights are at stake.

87 The Board did not have the jurisdiction to allocate the proceeds of the sale of the utility's asset; its decision did not meet the correctness standard. Thus, I would dismiss the City's appeal and allow ATCO's cross-appeal, both with costs. I would also set aside the Board's decision and refer the matter back to the Board to approve the sale of the property belonging to ATCO, recognizing that the proceeds of the sale belong to ATCO.

The reasons of McLachlin C.J. and Binnie and Fish JJ. were delivered by

88 BINNIE J. (dissenting):-- The respondent ATCO Gas and Pipelines Ltd. ("ATCO") is part of a large entrepreneurial company that directly and through various subsidiaries operates both regulated businesses and unregulated businesses. The Alberta Energy and Utilities Board ("Board") believes it not to be in the public interest to encourage utility companies to mix together the two types of undertakings. In particular, the Board has adopted policies to discourage utilities from using their regulated businesses as a platform to engage in land speculation to increase their return on investment outside the regulatory framework. By awarding part of the profit to the utility (and its shareholders), the Board rewards utilities for diligence in divesting themselves of assets that are no longer productive, or that could be more productively employed elsewhere. However, by crediting part of the [page187] profit on the sale of such property to the utility's rate base (i.e. as a set-off to other costs), the Board seeks to dampen any incentive for utilities to skew decisions in their regulated business to favour such profit taking unduly. Such a balance, in the Board's view, is necessary in the interest of the public which allows ATCO to operate its utility business as a monopoly. In pursuit of this balance, the Board approved ATCO's application to sell land and warehousing facilities in downtown Calgary, but denied ATCO's application to keep for its shareholders the entire profit resulting from appreciation in the value of the land, whose cost of acquisition had formed part of the rate base on which gas rates had been calculated since 1922. The Board ordered the profit on the sale to be allocated one third to ATCO and two thirds as a credit to its cost base, thereby helping keep utility rates down, and to that extent benefiting ratepayers.

89 I have read with interest the reasons of my colleague Bastarache J. but, with respect, I do not agree with his conclusion. As will be seen, the Board has authority under s. 15(3) of the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 ("AEUBA"), to impose on the sale "any additional conditions that the Board considers necessary in the public interest". Whether or not the conditions of approval imposed by the Board were necessary in the public interest was for the Board to decide. The Alberta Court of Appeal overruled the Board but, with respect, the Board is in a better position to assess necessity in this field for the protection of the public interest than either that court or this Court. I would allow the appeal and restore the Board's decision.

I. Analysis

90 ATCO's argument boils down to the proposition announced at the outset of its factum:

> In the absence of any property right or interest and of any harm to the customers arising from the [page188] withdrawal from utility service, there was no proper ground for reaching into the pocket of the utility. In essence this case is about property rights.
>
> (Respondent's factum, at para. 2)

91 For the reasons which follow I do not believe the case is about property rights. ATCO chose to make its investment in a regulated industry. The return on investment in the regulated gas industry is fixed by the Board, not the free market. In my view, the essential issue is whether the Alberta Court of Appeal was justified in limiting what the Board is allowed to "conside[r] necessary in the public interest".

A. *The Board's Statutory Authority*

92 The first question is one of jurisdiction. What gives the Board the authority to make the order ATCO complains about? The Board's answer is threefold. Section 22(1) of the *Gas Utilities Act*, R.S.A. 2000, c. G-5 ("GUA"), provides in part that "[t]he Board shall exercise a general supervision over all gas utilities, and the owners of them ...". This, the Board says, gives it a broad jurisdiction to set policies that go beyond its specific powers in relation to specific applications, such as rate setting. Of more immediate pertinence, s. 26(2)(d)(i) of the same Act prohibits the regulated utility from selling, leasing or otherwise encumbering any of its property without the Board's approval. (To the same effect, see s. 101(2)(d)(i) of the *Public Utilities Board Act*, R.S.A. 2000, c. P-45.) It is common ground that this restraint on alienation of property applies to the proposed sale of ATCO's land and warehouse facilities in downtown Calgary, and that the Board could, in appropriate circumstances, simply have denied ATCO's application for approval of the sale. However, the Board was of the view to allow the sale subject to conditions. The Board ruled that the greater power (i.e. to deny the sale) must include the lesser (i.e. to allow the sale, subject to conditions):

> In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. [page189] In the Board's view it also follows that the Board can approve a disposition subject to appropriate conditions to protect customer interests.
>
> (Decision 2002-037, [2002] A.E.U.B.D. No. 52 (QL), at para. 47)

There is no need to rely on any such implicit power to impose conditions, however. As stated, the Board's explicit power to impose conditions is found in s. 15(3) of the AEUBA, which authorizes the Board to "make any further order and impose any additional conditions that the Board considers necessary in the public interest". In *Atco Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at p. 576, Estey J., for the majority, stated:

> It is evident from the powers accorded to the Board by the legislature in both statutes mentioned above that the legislature has given the Board <u>a mandate of the widest proportions to safeguard the public interest</u> in the nature and quality of the service provided to the community by the public utilities. [Emphasis added.]

The legislature says in s. 15(3) that the conditions are to be what *the Board* considers necessary. Of course, the discretionary power to impose conditions thus granted is not unlimited. It must be exercised in good faith for its intended purpose: *C.U.P.E. v. Ontario (Minister of Labour)*, [2003] 1

S.C.R. 539, 2003 SCC 29. ATCO says the Board overstepped even these generous limits. In ATCO's submission:

> Deployment of the asset in utility service does not create or transfer any legal or equitable rights in that property for ratepayers. Absent any such interest, any taking such as ordered by the Board is confiscatory ... .
>
> (Respondent's factum, at para. 38)

In my view, however, the issue before the Board was how much profit ATCO was entitled to earn on its investment in a regulated utility.

93 ATCO argues in the alternative that the Board engaged in impermissible "retroactive rate [page190] making". But Alberta is an "original cost" jurisdiction, and no one suggests that the Board's original cost rate making during the 80-plus years this investment has been reflected in ATCO's ratebase was wrong. The Board proposed to apply a portion of the expected profit to future rate making. The effect of the order is prospective, not retroactive. Fixing the going-forward rate of return as well as general supervision of "all gas utilities, and the owners of them" were matters squarely within the Board's statutory mandate.

B. *The Board's Decision*

94 ATCO argues that the Board's decision should be seen as a stand-alone decision divorced from its rate-making responsibilities. However, I do not agree that the hearing under s. 26 of the GUA can be isolated in this way from the Board's general regulatory responsibilities. ATCO argues in its factum that

> the subject application by [ATCO] to the Board did not concern or relate to a rate application, and the Board was not engaged in fixing rates (if that could provide any justification, which is denied).
>
> (Respondent's factum, at para. 98)

95 It seems the Board proceeded with the s. 26 approval hearing separately from a rate setting hearing firstly because ATCO framed the proceeding in that way and secondly because this is the procedure approved by the Alberta Court of Appeal in *TransAlta Utilities Corp. v. Public Utilities Board (Alta.)* (1986), 68 A.R. 171. That case (which I will refer to as *TransAlta (1986)*) is a leading Alberta authority dealing with the allocation of the gain on the disposal of utility assets and the source of what is called the *TransAlta Formula* applied by the Board in this case. Kerans J.A. had this to say, at p. 174:

> I observe parenthetically that I now appreciate that it suits the convenience of everybody involved to resolve [page191] issues of this sort, if possible, before a general rate hearing so as to lessen the burden on that already complex procedure.

96 Given this encouragement from the Alberta Court of Appeal, I would place little significance on ATCO's procedural point. As will be seen, the Board's ruling is directly tied into the setting of general rates because two thirds of the profit is taken into account as an offset to ATCO's costs from which its revenue requirement is ultimately derived. As stated, ATCO's profit on the sale of the Calgary property will be a current (not historical) receipt and, if the Board has its way, two thirds of it will be applied to future (not retroactive) rate making.

97 The s. 26 hearing proceeded in two phases. The Board first determined that it would not deny its approval to the proposed sale as it met a "no-harm test" devised over the years by Board practice (it is not to be found in the statutes) (Decision 2001-78). However, the Board linked its approval to subsequent consideration of the financial ramifications, as the Board itself noted:

> The Board approved the Sale in Decision 2001-78 based on evidence that customers did not object to the Sale [and] would not suffer a reduction in services nor would they be exposed to the risk of financial harm as a result of the Sale *that could not be examined in a future proceeding*. On that basis the Board determined that the no-harm test had been satisfied and that the Sale could proceed. [Underlining and italics added.] (Decision 2002-037, at para. 13)

98 In effect, ATCO ignores the italicized words. It argues that the Board was *functus* after the first phase of its hearing. However, ATCO itself had agreed to the two-phase procedure, and indeed the second phase was devoted to ATCO's own application for an allocation of the profits on the sale.

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99 In the second phase of the s. 26 approval hearing, the Board allocated one third of the net gain to ATCO and two thirds to the rate base (which would benefit ratepayers). The Board spelled out why it considered these conditions to be necessary in the public interest. The Board explained that it was necessary to balance the interests of both shareholders and ratepayers within the framework of what it called "the regulatory compact" (Decision 2002-037, at para. 44). In the Board's view:

(a) there ought to be a balancing of the interests of the ratepayers and the owners of the utility;

(b) decisions made about the utility should be driven by both parties' interests;

(c) to award the entire gain to the ratepayers would deny the utility an incentive to increase its efficiency and reduce its costs; and

(d) to award the entire gain to the utility might encourage speculation in non-depreciable property or motivate the utility to identify and dispose of properties which have appreciated for reasons other than the best interest of the regulated business.

100 For purposes of this appeal, it is important to set out the Board's policy reasons in its own words:

> To award the entire net gain on the land and buildings to the customers, while beneficial to the customers, could establish an environment that may deter the process wherein the company continually assesses its operation to identify, evaluate, and select options that continually increase efficiency and reduce costs.
>
> Conversely, to award the entire net gain to the company may establish an environment where a regulated utility company might be moved to speculate in non-depreciable property or result in the company being motivated to identify and sell existing properties where appreciation has already occurred.
>
> The Board believes that some method of balancing both parties' interests will result in optimization [page193] of business objectives for both the customer and the company. Therefore, the Board considers that sharing of the net gain on the sale of the land and buildings collectively in accordance with the TransAlta Formula is equitable in the circumstances of this application and is consistent with past Board decisions.

[Emphasis added; paras. 112-14.]

101 The Court was advised that the two-third share allocated to ratepayers would be included in ATCO's rate calculation to set off against the costs included in the rate base and amortized over a number of years.

C. *Standard of Review*

102 The Court's modern approach to this vexed question was recently set out by McLachlin C.J. in *Dr. Q v. College of Physicians and Surgeons of British Columbia*, [2003] 1 S.C.R. 226, 2003 SCC 19, at para. 26:

> In the pragmatic and functional approach, the standard of review is determined by considering four contextual factors the presence or absence of a privative clause or statutory right of appeal; the expertise of the tribunal relative to that of the reviewing court on the issue in question; the purposes of the legislation and the provision in particular; and, the nature of the question law, fact, or mixed law and fact. The factors may overlap. The overall aim is to discern legislative intent, keeping in mind the constitutional role of the courts in maintaining the rule of law.

103 I do not propose to cover the ground already set out in the reasons of my colleague Bastarache J. We agree that the standard of review on matters of jurisdiction is correctness. We also agree that the Board's *exercise* of its jurisdiction calls for greater judicial deference. Appeals from the Board are limited to questions of law or jurisdiction. The Board knows a great deal more than the courts about gas utilities, and what limits it is necessary to impose "in the public interest" on their dealings with assets whose cost is included in the rate base. Moreover, it is difficult to think of a broader discretion than that conferred on the Board to "impose any additional conditions that the Board considers necessary in the public interest" (s. 15(3)(d) of the AEUBA). [page194] The identification of a subjective discretion in the decision maker ("the Board considers necessary"), the expertise of that decision maker and the nature of the decision to be made ("in the public interest"), in my view, call for the most deferential standard, patent unreasonableness.

104 As to the phrase "the Board considers necessary", Martland J. stated in *Calgary Power Ltd. v. Copithorne*, [1959] S.C.R. 24, at p. 34:

> The question as to whether or not the respondent's lands were "necessary" is not one to be determined by the Courts in this case. The question is whether the Minister "deemed" them to be necessary.

See also D. J. M. Brown and J. M. Evans, *Judicial Review of Administrative Action in Canada* (loose-leaf ed.), vol. 1, at para. 14:2622: "*'Objective' and 'Subjective' Grants of Discretion*".

105 The expert qualifications of a regulatory Board are of "utmost importance in determining the intention of the legislator with respect to the degree of deference to be shown to a tribunal's decision in the absence of a full privative clause", as stated by Sopinka J. in *United Brotherhood of Carpenters and Joiners of America, Local 579 v. Bradco Construction Ltd.*, [1993] 2 S.C.R. 316, at p. 335. He continued:

> Even where the tribunal's enabling statute provides explicitly for appellate review, as was the case in *Bell Canada* [*v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722], it has been stressed that deference should be shown by the appellate tribunal to the opinions of the specialized lower tribunal on matters squarely within its jurisdiction.

(This *dictum* was cited with approval in *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557, at p. 592.)

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106 A regulatory power to be exercised "in the public interest" necessarily involves accommodation of conflicting economic interests. It has long been recognized that what is "in the public interest" is not really a question of law or fact but is an opinion. In *TransAlta (1986)*, the Alberta Court of Appeal (at para. 24) drew a parallel between the scope of the words "public interest" and the well-known phrase "public convenience and necessity" in its citation of *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353, where this Court stated, at p. 357:

> [T]he question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest ... . [Emphasis added.]

107 This passage reiterated the *dictum* of Rand J. in *Union Gas Co. of Canada Ltd. v. Sydenham Gas and Petroleum Co.*, [1957] S.C.R. 185, at p. 190:

> It was argued, and it seems to have been the view of the Court, that the determination of public convenience and necessity was itself a question of fact, but with that I am unable to agree: it is not an objective existence to be ascertained; the determination is the formulation of an opinion, in this case, the opinion of the Board and of the Board only. [Emphasis added.]

108 Of course even such a broad power is not untrammelled. But to say that such a power is capable of abuse does not lead to the conclusion that it should be truncated. I agree on this point with Reid J. (co-author of R. F. Reid and H. David, *Administrative Law and Practice* (2nd ed. 1978), and co-editor of P. Anisman and R. F. Reid, *Administrative Law Issues and Practice* (1995)), who wrote in *Re C.T.C. Dealer Holdings Ltd. and Ontario Securities Commission* (1987), 59 O.R. (2d) 79 (Div. Ct.), in relation to the powers of the Ontario Securities Commission, at p. 97:

[page196]

> ... when the Commission has acted *bona fide*, with an obvious and honest concern for the public interest, and with evidence to support its opinion, the prospect that the breadth of its discretion might someday tempt it to place itself above the law by misusing that discretion is not something that makes the existence of the discretion bad *per se*, and requires the decision to be struck down.

(The *C.T.C. Dealer Holdings* decision was referred to with apparent approval by this Court in *Committee for the Equal Treatment of Asbestos Minority Shareholders v. Ontario (Securities Commission)*, [2001] 2 S.C.R. 132, 2001 SCC 37, at para. 42.)

109 "Patent unreasonableness" is a highly deferential standard:

> A correctness approach means that there is only one proper answer. A patently

> unreasonable one means that there could have been many appropriate answers, but not the one reached by the decision maker.
>
> (*C.U.P.E.*, at para. 164)

110 Having said all that, in my view nothing much turns on the result on whether the proper standard in that regard is patent unreasonableness (as I view it) or simple reasonableness (as my colleague sees it). As will be seen, the Board's response is well within the range of established regulatory opinions. Hence, even if the Board's conditions were subject to the less deferential standard, I would find no cause for the Court to interfere.

D. *Did the Board Have Jurisdiction to Impose the Conditions It Did on the Approval Order "In the Public Interest"?*

111 ATCO says the Board had no jurisdiction to impose conditions that are "confiscatory". Framing the question in this way, however, assumes the point in issue. The correct point of departure is not to assume that ATCO is entitled to the net gain and then ask if the Board can confiscate it. ATCO's investment of $83,000 was added in increments to its regulatory cost base as the land was acquired from [page197] time to time between 1922 and 1965. It is in the nature of a regulated industry that the question of what is a just and equitable return is determined by a board and not by the vagaries of the speculative property market.

112 I do not think the legal debate is assisted by talk of "confiscation". ATCO is prohibited by statute from disposing of the asset without Board approval, and the Board has statutory authority to impose conditions on its approval. The issue thus necessarily turns not on the *existence* of the jurisdiction but on the *exercise* of the Board's jurisdiction to impose the conditions that it did, and in particular to impose a shared allocation of the net gain.

E. *Did the Board Improperly Exercise the Jurisdiction It Possessed to Impose Conditions the Board Considered "Necessary in the Public Interest"?*

113 There is no doubt that there are many approaches to "the public interest". Which approach the Board adopts is largely (and inherently) a matter of opinion and discretion. While the statutory framework of utilities regulation varies from jurisdiction to jurisdiction, and practice in the United States must be read in light of the constitutional protection of property rights in that country, nevertheless Alberta's grant of authority to its Board is more generous than most. ATCO concedes that its "property" claim would have to give way to a contrary legislative intent, but ATCO says such intent cannot be found in the statutes.

114 Most if not all regulators face the problem of how to allocate gains on property whose original cost is included in the rate base but is no longer required to provide the service. There is a wealth of regulatory experience in many jurisdictions that the Board is entitled to (and does) have regard to in formulating its policies. Striking the correct balance in the allocation of gains between ratepayers [page198] and investors is a common preoccupation of comparable boards and agencies:

> First, it prevents the utility from degrading the quality, or reducing the quantity, of the regulated service so as to harm consumers. Second, it ensures that the utility maximizes the aggregate economic benefits of its operations, and not merely the benefits flowing to some interest group or stakeholder. Third, it specifically seeks to prevent favoritism toward investors to the detriment of ratepayers affected by the transaction.
>
> (P. W. MacAvoy and J. G. Sidak, "The Efficient Allocation of Proceeds from a Utility's Sale of Assets" (2001), 22 *Energy L.J.* 233, at p. 234)

115 The concern with which Canadian regulators view utilities under their jurisdiction that are speculating in land is not new. In *Re Consumers' Gas Co.*, E.B.R.O. 341-I, June 30, 1976, the Ontario Energy Board considered how to deal with a real estate profit on land which was disposed of at an after-tax profit of over $2 million. The Board stated:

> The Station "B" property was not purchased by Consumers' for land speculation but was acquired for utility purposes. This investment, while non-depreciable, was subject to interest charges and risk paid for through revenues and, until the gas manufacturing plant became obsolete, disposal of the land was not a feasible option. If, in such circumstances, the Board were to permit real estate profit to accrue to the shareholders only, it would tend to encourage real estate speculation with utility capital. In the Board's opinion, the shareholders and the ratepayers should share the benefits of such capital gains. [Emphasis added; para. 326.]

116 Some U.S. regulators also consider it good regulatory policy to allocate part or all of the profit to offset costs in the rate base. In *Re Boston Gas Co.*, 49 P.U.R. 4th 1 (Mass. D.P.U. 1982), the regulator allocated a gain on the sale of land to ratepayers, stating:

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> The company and its shareholders have received a return on the use of these parcels while they have been included in rate base, and are not entitled to any additional return as a result of their sale. To hold otherwise would be to find that a regulated utility company may speculate in nondepreciable utility property and, despite earning a reasonable rate of return from its customers on that property, may also accumulate a windfall through its sale. We find this to be an uncharacteristic risk/reward situation for a regulated utility to be in with respect to its plant in service. [Emphasis added; p. 26.]

117 Canadian regulators other than the Board are also concerned with the prospect that decisions of utilities in their regulated business may be skewed under the undue influence of prospective profits on land sales. In *Re Consumers' Gas Co.*, E.B.R.O. 465, March 1, 1991, the Ontario Energy Board determined that a $1.9 million gain on sale of land should be divided equally between shareholders and ratepayers. It held that

> the allocation of 100 percent of the profit from land sales to either the shareholders or the ratepayers might diminish the recognition of the valid concerns of the excluded party. For example, the timing and intensity of land purchase and sales negotiations could be skewed to favour or disregard the ultimate beneficiary. [para. 3.3.8]

118 The Board's principle of dividing the gain between investors and ratepayers is consistent, as well, with *Re Natural Resource Gas Ltd.*, RP-2002-0147, EB-2002-0446, June 27, 2003, in which the Ontario Energy Board addressed the allocation of a profit on the sale of land and buildings and again stated:

> The Board finds that it is reasonable in the circumstances that the capital gains be shared equally between the Company and its customers. In making this finding the Board has considered the non-recurring nature of this transaction. [para. 45]

119 The wide variety of regulatory treatment of such gains was noted by Kerans J.A. in *TransAlta (1986)*, at pp. 175-76, including *Re Boston Gas Co.* [page200] mentioned earlier. In *TransAlta (1986)*, the Board characterized TransAlta's gain on the disposal of land and buildings included in its Edmonton "franchise" as "revenue" within the meaning of the *Hydro and Electric Energy Act*, R.S.A. 1980, c. H-13. (The case therefore did not deal with the power to impose conditions "the Board considers necessary in the public interest".) Kerans J.A. said (at p. 176):

> I do not agree with the Board's decision for reasons later expressed, but it would be fatuous to deny that its interpretation [of the word "revenue"] is one which the word can reasonably bear.

Kerans J.A. went on to find that in that case "[t]he compensation was, for all practical purposes, compensation for loss of franchise" (p. 180) and on that basis the gain in these "unique circumstances" (p. 179) could not, as a matter of law, be characterized as revenue, i.e. applying a correctness standard. The range of regulatory practice on the "gains on sale" issue was similarly noted by Goldie J.A. in *Yukon Energy Corp. v. Utilities Board* (1996), 74 B.C.A.C. 58 (Y.C.A.), at para. 85.

120 A survey of recent regulatory experience in the United States reveals the wide variety of treatment in that country of gains on the sale of undepreciated land. The range includes proponents of ATCO's preferred allocation as well as proponents of the solution adopted by the Board in this case:

> Some jurisdictions have concluded that as a matter of equity, shareholders alone should benefit from any gain realized on appreciated real estate, because ratepayers generally pay only for taxes on the land and do not contribute to the cost of acquiring the property and pay no depreciation expenses. Under this analysis, ratepayers assume no risk for losses and acquire no legal or equitable interest in the property, but rather pay only for the use of the land in utility service.
>
> Other jurisdictions claim that ratepayers should retain some of the benefits associated with the sale of property dedicated to utility service. Those jurisdictions that have adopted an equitable sharing approach agree that a review of regulatory and judicial decisions [page201] on the issue does not reveal any general principle that requires the allocation of benefits solely to shareholders; rather, the cases show only a general prohibition against sharing benefits on the sale property that has never been reflected in utility rates.
>
> (P. S. Cross, "Rate Treatment of Gain on Sale of Land: Ratepayer Indifference, A New Standard?" (1990), 126 *Pub. Util. Fort.* 44, at p. 44)

Regulatory opinion in the United States favourable to the solution adopted here by the Board is illustrated by *Re Arizona Public Service Co.*, 91 P.U.R. 4th 337 (Ariz. C.C. 1988), at p. 361:

> To the extent any general principles can be gleaned from the decisions in other jurisdictions they are: (1) the utility's stockholders are not *automatically* entitled to the gains from all sales of utility property; and (2) ratepayers are not entitled to all or any part of a gain from the sale of property which has never been reflected in the utility's rates. [Emphasis in original.]

121 Assets purchased with capital reflected in the rate base come and go, but the utility itself endures. What was done by the Board in this case is quite consistent with the "enduring enterprise" theory espoused, for example, in *Re Southern California Water Co.*, 43 C.P.U.C. 2d 596 (1992). In that case, Southern California Water had asked for approval to sell an old headquarters building and the issue was how to allocate its profits on the sale. The Commission held:

> Working from the principle of the "enduring enterprise", the gain-on-sale from this transaction should remain within the utility's operations rather than being distributed ir the short run directly to either ratepayers or shareholders.
>
> The "enduring enterprise" principle, is neither novel nor radical. It was clearly articulated by the Commission in its seminal 1989 policy decision on the issue of gain-on-sale, D.89-07-016, 32 Cal. P.U.C.2d 233 (*Redding*). Simply stated, to the extent that a utility realizes a gain-on-sale from the liquidation of an asset and replaces it witr another asset or obligation while at [page202] the same time its responsibility to serve its customers is neither relieved nor reduced, then any gain-on-sale should remain within the utility's operation. [p. 604]

122 In my view, neither the Alberta statutes nor regulatory practice in Alberta and elsewhere dictates the answer to the problems confronting the Board. It would have been open to the Board to allow ATCO's application for the entire profit. But the solution it adopted was quite within its statutory authority and does not call for judicial intervention.

F. *ATCO's Arguments*

123 Most of ATCO's principal submissions have already been touched on but I will repeat them here for convenience. ATCO does not really dispute the Board's ability to impose conditions on the sale of land. Rather, ATCO says that what the Board did here violates a number of basic legal protections and principles. It asks the Court to clip the Board's wings.

124 Firstly, ATCO says that customers do not acquire any proprietary right in the company's assets. ATCO, rather than its customers, originally purchased the property, held title to it, and therefore was entitled to any gain on its sale. An allocation of profit to the customers would amount to a confiscation of the corporation's property.

125 Secondly, ATCO says its retention of 100 percent of the gain has nothing to do with the so-called "regulatory compact". The gas customers paid what the Board regarded over the years as a fair price for safe and reliable service. That is what the ratepayers got and that is all they were entitled to. The Board's allocation of part of the profit to the ratepayers amounts to impermissible "retroactive" rate setting.

126 Thirdly, utilities are not entitled to include in the rate base an amount for *depreciation* on land and ratepayers have therefore not repaid ATCO any part of ATCO's original cost, let alone the present value. The treatment accorded gain on sales of depreciated property therefore does not apply.

[page203]

127 Fourthly, ATCO complains that the Board's solution is asymmetrical. Ratepayers are given part of the benefit of an increase in land values without, in a falling market, bearing any part of the burden of losses on the disposition of land.

128 In my view, these are all arguments that should be (and were) properly directed to the Board. There are indeed precedents in the regulatory field for what ATCO proposes, just as there are precedents for what the ratepayers proposed. It was for the Board to decide what conditions in these particular circumstances were necessary in the public interest. The Board's solution in this case is well within the range of reasonable options, as I will endeavour to demonstrate.

1. The Confiscation Issue

129 In its factum, ATCO says that "[t]he property belonged to the owner of the utility and the Board's proposed distribution cannot be characterized otherwise than as being confiscatory" (respondent's factum, at para. 6). ATCO's argument overlooks the obvious difference between investment in an unregulated business and investment in a regulated utility where the regulator sets the return on investment, not the marketplace. In *Re Southern California Gas Co.*, 118 P.U.R. 4th 81 (C.P.U.C. 1990) ("*SoCalGas*"), the regulator pointed out:

> In the non-utility private sector, investors are not guaranteed to earn a fair return on such sunk investment. Although shareholders and bondholders provide the initial capital investment, the ratepayers pay the taxes, maintenance, and other costs of carrying utility property in rate base over the years, and thus insulate utility investors from the risk of having to pay those costs. Ratepayers also pay the utility a fair return on property (including land) while it is in rate base, compensate the utility for the diminishment of the value of its depreciable property over time through depreciation [page204] accounting, and bear the risk that they must pay depreciation and a return on prematurely retired rate base property. [p. 103]

(It is understood, of course, that the Board does not appropriate the actual proceeds of sale. What happens is that an amount *equivalent* to two-thirds of the profit is included in the calculation of ATCO's current cost base for rate-making purposes. In that way, there is a notional distribution of the benefit of the gain amongst the competing stakeholders.)

130 ATCO's argument is frequently asserted in the United States under the flag of constitutional protection for "property". Constitutional protection has not however prevented allocation of all or part of such gains to the U.S. ratepayers. One of the leading U.S. authorities is *Democratic Central Committee of the District of Columbia v. Washington Metropolitan Area Transit Commission*, 485 F.2d 786 (D.C. Cir. 1973). In that case, the assets at issue were parcels of real estate which had been employed in mass transit operations but which were no longer needed when the transit system converted to buses. The regulator awarded the profit on the appreciated land values to the shareholders but the Court of Appeals reversed the decision, using language directly applicable to ATCO's "confiscation" argument:

> We perceive no impediment, constitutional or otherwise, to recognition of a ratemaking principle enabling ratepayers to benefit from appreciations in value of utility properties accruing while in service. We believe the doctrinal consideration upon which pronouncements to the contrary have primarily rested has lost all present-day vitality. Underlying these pronouncements is a basic legal and economic thesis sometimes articulated, sometimes implicit that utility assets, though dedicated to the public service, remain exclusively the property of the utility's investors, and that growth in value is an inseparable and inviolate incident of that property interest. The precept of private ownership historically pervading our jurisprudence led naturally to such a thesis, and early decisions in the ratemaking field lent some support to it; if still viable, it strengthens the investor's claim. We think, however, after careful [page205] exploration, that the foundations for that approach, and the conclusion it seemed to indicate, have long since eroded away. [p. 800]

The court's reference to "pronouncements" which have "lost all present-day vitality" likely includes *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23 (1976), a decision relied upon in this case by ATCO. In that case, the Supreme Court of the United States said:

> Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation or other operating expenses or to capital of the company. By paying bills for service they do not acquire any interest, legal or

> equitable, in the property used for their convenience or in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stock. [p. 32]

In that case, the regulator belatedly concluded that the level of depreciation allowed the New York Telephone Company had been excessive in past years and sought to remedy the situation in the current year by retroactively adjusting the cost base. The court held that the regulator had no power to re-open past rates. The financial fruits of the regulator's errors in past years now belonged to the company. That is not this case. No one contends that the Board's prior rates, based on ATCO's original investment, were wrong. In 2001, when the matter came before the Board, the Board had jurisdiction to approve or not approve the proposed sale. It was not a done deal. The receipt of any profit by ATCO was prospective only. As explained in *Re Arizona Public Service Co.*:

> In *New York Telephone*, the issue presented was whether a state regulatory commission could use excessive depreciation accruals from prior years to reduce rates for future service and thereby set rates which did not yield a just return... . [T]he Court simply reiterated and provided the reasons for a ratemaking truism: rates must be designed to produce enough revenue to pay [page206] current (reasonable) operating expenses and provide a fair return to the utility's investors. If it turns out that, for whatever reason, existing rates have produced too much or too little income, the past is past. <u>Rates are raised or lowered to reflect current conditions; they are not designed to pay back past excessive profits or recoup past operating losses.</u> In contrast, the issue in this proceeding is whether for ratemaking purposes a utility's test year income from sales of utility service can include its income from sales of utility property. The United States Supreme Court's decision in *New York Telephone* does not address that issue. [Emphasis added; p. 361.]

131 More recently, the allocation of gain on sale was addressed by the California Public Utilities Commission in *SoCalGas*. In that case, as here, the utility (SoCalGas) wished to sell land and buildings located (in that case) in downtown Los Angeles. The Commission apportioned the gain on sale between the shareholders and the ratepayers, concluding that:

> We believe that the issue of who owns the utility property providing utility service has become a red herring in this case, and that ownership alone does not determine who is entitled to the gain on the sale of the property providing utility service when it is removed from rate base and sold. [p. 100]

132 ATCO argues in its factum that ratepayers "do not acquire any interest, legal or equitable, in the property used to provide the service or in the funds of the owner of the utility" (para. 2). In *SoCalGas*, the regulator disposed of this point as follows:

> No one seriously argues that ratepayers acquire title to the physical property assets used to provide utility service; DRA [Division of Ratepayer Advocates] argues that the gain on sale should reduce future revenue requirements not because ratepayers own the property, but rather because they paid the costs and faced the risks associated with that property while it was in rate base providing public service. [p. 100]

[page207]

This "risk" theory applies in Alberta as well. Over the last 80 years, there have been wild swings in Alberta real estate, yet through it all, in bad times and good, the ratepayers have guaranteed ATCO a just and equitable return on its investment in *this* land and *these* buildings.

133 The notion that the division of risk justifies a division of the net gain was also adopted by the regulator in *SoCalGas*:

> Although the shareholders and bondholders provided the initial capital investment, the ratepayers paid the taxes, maintenance, and other costs of carrying the land and buildings in rate base over the years, and paid the utility a fair return on its unamortized investment in the land and buildings while they were in rate base. [p. 110]

In other words, even in the United States, where property rights are constitutionally protected, ATCO's "confiscation" point is rejected as an oversimplification.

134 My point is not that the Board's allocation in this case is necessarily correct in all circumstances. Other regulators have determined that the public interest requires a different allocation. The Board proceeds on a "case-by-case" basis. My point simply is that the Board's response in this case cannot be considered "confiscatory" in any proper use of the term, and is well within the range of what are regarded in comparable jurisdictions as appropriate regulatory responses to the allocation of the gain on sale of land whose original investment has been included by the utility itself in its rate base. The Board's decision is protected by a deferential standard of review and in my view it should not have been set aside.

2. The Regulatory Compact

135 The Board referred in its decision to the "regulatory compact" which is a loose expression suggesting that in exchange for a statutory monopoly [page208] and receipt of revenue on a cost plus basis, the utility accepts limitations on its rate of return and its freedom to do as it wishes with property whose cost is reflected in its rate base. This was expressed in the *Washington Metropolitan Area Transit* case by the U.S. Court of Appeals for the District of Columbia Circuit as follows:

> The ratemaking process involves fundamentally "a balancing of the investor and the consumer interests". The investor's interest lies in the integrity of his investment and a fair opportunity for a reasonable return thereon. The consumer's interest lies in governmental protection against unreasonable charges for the monopolistic service to which he subscribes. In terms of property value appreciations, the balance is best struck at the point at which the interests of both groups receive maximum accommodation. [p. 806]

136 ATCO considers that the Board's allocation of profit violated the regulatory compact not only because it is confiscatory but because it amounts to "retroactive rate making". In *Northwestern Utilities Ltd. v. City of Edmonton*, [1979] 1 S.C.R. 684, Estey J. stated, at p. 691:

> It is clear from many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods.

137 As stated earlier, the Board in this case was addressing a prospective receipt and allocated two thirds of it to a prospective (not retroactive) rate-making exercise. This is consistent with regulatory practice, as is illustrated by *New York Water Service Corp. v. Public Service Commission*, 208 N.Y.S.2d 857 (1960). In that case, a utility commission ruled that gains on the sale of real estate should be taken into account to reduce rates annually over the following period of 17 years :

> If land is sold at a profit, it is required that the profit be added to, i.e., "credited to", the depreciation reserve, so [page209] that there is a corresponding reduction of the rate base and resulting return. [p. 864]

The regulator's order was upheld by the New York State Supreme Court (Appellate Division).

138 More recently, in *Re Compliance with the Energy Policy Act of 1992*, 62 C.P.U.C. 2d 517 (1995), the regulator commented:

> ... we found it appropriate to allocate the principal amount of the gain to offset future costs of headquarters facilities, because ratepayers had borne the burden of risks and expenses while the property was in ratebase. At the same time, we found that it was equitable to allocate a portion of the benefits from the gain-on-sale to shareholders in order to provide a reasonable incentive to the utility to maximize the proceeds from selling such property and compensate shareholders for any risks borne in connection with holding the former property. [p. 529]

139 The emphasis in all these cases is on balancing the interests of the shareholders and the ratepayers. This is perfectly consistent with the "regulatory compact" approach reflected in the Board doing what it did in this case.

3. <u>Land as a Non-Depreciable Asset</u>

140 The Alberta Court of Appeal drew a distinction between gains on sale of land, whose original cost is not depreciated (and thus is not repaid in increments through the rate base) and depreciated property such as buildings where the rate base does include a measure of capital repayment and which in that sense the ratepayers have "paid for". The Alberta Court of Appeal held that the Board was correct to credit the rate base with an amount equivalent to the depreciation paid in respect of the buildings (this is the subject matter of ATCO's cross-appeal). Thus, in this case, the land was still carried on ATCO's books at its original price of $83,720 whereas the original $596,591 cost of the buildings had been depreciated through the rates charged customers to a net book value of $141,525.

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141 Regulatory practice shows that many (not all) regulators also do not accept the distinction (for this purpose) between depreciable and non-depreciable assets. In *Re Boston Gas Co.* for example (cited in *TransAlta (1986)*, at p. 176), the regulator held:

> ... the company's ratepayers have been paying a return on this land as well as all other costs associated with its use. The fact that land is a nondepreciable asset because its useful value is not ordinarily diminished through use is, we find, irrelevant to the question of who is entitled to the proceeds on the sales of this land. [p. 26]

142 In *SoCalGas*, as well, the Commission declined to make a distinction between the gain on sale of depreciable, as compared to non-depreciable, property, stating: "We see little reason why land sales should be treated differently" (p. 107). The decision continued:

> In short, whether an asset is depreciated for ratemaking purposes or not, ratepayers commit to paying a return on its book value for as long as it is used and useful. Depreciation simply recognizes the fact that certain assets are consumed over a period of utility service while others are not. <u>The basic relationship between the utility and its ratepayers is the same for depreciable and non-depreciable assets.</u> [Emphasis

added; p. 107.]

143 In *Re California Water Service Co.*, 66 C.P.U.C. 2d 100 (1996), the regulator commented that:

> Our decisions generally find no reason to treat gain on the sale of nondepreciable property, such as bare land, different[ly] than gains on the sale of depreciable rate base assets and land in PHFU [plant held for future use]. [p. 105]

144 Again, my point is not that the regulator *must* reject any distinction between depreciable and non-depreciable property. Simply, my point is that the distinction does not have the controlling weight as contended by ATCO. In Alberta, it is up to the [page211] Board to determine what allocations are necessary in the public interest as conditions of the approval of sale. ATCO's attempt to limit the Board's discretion by reference to various doctrine is not consistent with the broad statutory language used by the Alberta legislature and should be rejected.

4. Lack of Reciprocity

145 ATCO argues that the customers should not profit from a rising market because if the land loses value it is ATCO, and not the ratepayers, that will absorb the loss. However, the material put before the Court suggests that the Board takes into account both gains *and* losses. In the following decisions the Board stated, repeated, and repeated again its "general rule" that

> the Board considers that any profit or loss (being the difference between the net book value of the assets and the sale price of those assets) resulting from the disposal of utility assets should accrue to the customers of the utility and not to the owner of the utility. [Emphasis added.]

(See *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84116, October 12, 1984, at p. 17; *Re TransAlta Utilities Corp.*, Alta. P.U.B., Decision No. E84115, October 12, 1984, at p. 12; *Re Canadian Western Natural Gas Co.*, Alta. P.U.B., Decision No. E84113, October 12, 1984, at p. 23.)

146 In *Re Alberta Government Telephones*, Alta. P.U.B., Decision No. E84081, June 29, 1984, the Board reviewed a number of regulatory approaches (including *Re Boston Gas Co.*, previously mentioned) with respect to gains on sale and concluded with respect to its own practice, at p. 12:

> The Board is aware that it has not applied any consistent formula or rule which would automatically determine the accounting procedure to be followed in the treatment of gains or losses on the disposition of utility assets. The reason for this is that the Board's determination of what is fair and reasonable rests on the merits or facts of each case.

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147 ATCO's contention that it alone is burdened with the risk on land that *declines* in value overlooks the fact that in a falling market the utility continues to be entitled to a rate of return on its original investment, even if the market value at the time is substantially less than its original investment. As pointed out in *SoCalGas*:

> If the land actually does depreciate in value below its original cost, then one view could be that the steady rate of return [the ratepayers] have paid for the land over time has actually overcompensated investors. Thus, there is symmetry of risk and reward associated with rate base land just as there is with regard to depreciable rate base

property. [p. 107]

II. Conclusion

148 In summary, s. 15(3) of the AEUBA authorized the Board in dealing with ATCO's application to approve the sale of the subject land and buildings to "impose any additional conditions that the Board considers necessary in the public interest". In the exercise of that authority, and having regard to the Board's "general supervision over all gas utilities, and the owners of them" (GUA, s. 22(1)), the Board made an allocation of the net gain for the public policy reasons which it articulated in its decision. Perhaps not every regulator and not every jurisdiction would exercise the power in the same way, but the allocation of the gain on an asset ATCO sought to withdraw from the rate base was a decision the Board was mandated to make. It is not for the Court to substitute its own view of what is "necessary in the public interest".

Disposition

149 I would allow the appeal, set aside the decision of the Alberta Court of Appeal, and restore the decision of the Board, with costs to the City of Calgary both in this Court and in the court below. ATCO's cross-appeal should be dismissed with costs.

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* * * * *

APPENDIX

Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17

Jurisdiction

13 All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.

Powers of the Board

15(1) For the purposes of carrying out its functions, the Board has all the powers, rights and privileges of the ERCB and the PUB that are granted or provided for by any enactment or by law.

(2) In any case where the ERCB, the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion.

(3) Without restricting subsection (1), the Board may do all or any of the following:

(a) make any order that the ERCB or the PUB may make under any enactment;

(b) with the approval of the Lieutenant Governor in Council, make any order that the ERCB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(c) with the approval of the Lieutenant Governor in Council, make any order that the PUB may, with the approval of the Lieutenant Governor in Council, make under any enactment;

(d) with respect to an order made by the Board, the ERCB or the PUB in respect of matters referred to in clauses (a) to (c), make any further order and impose any additional conditions that the Board considers necessary in the public interest;

(e) make an order granting the whole or part only of the relief applied for;

(f) where it appears to the Board to be just and proper, grant partial, further or other relief in [page214] addition to, or in substitution for, that applied for as fully and in all respects as if the application or matter had been for that partial, further or other relief.

Appeals

26(1) Subject to subsection (2), an appeal lies from the Board to the Court of Appeal on a question of jurisdiction or on a question of law.

(2) Leave to appeal may be obtained from a judge of the Court of Appeal only on an application made

(a) within 30 days from the day that the order, decision or direction sought to be appealed from was made, or

(b) within a further period of time as granted by the judge where the judge is of the opinion that the circumstances warrant the granting of that further period of time.

...

Exclusion of prerogative writs

27 Subject to section 26, every action, order, ruling or decision of the Board or the person exercising the powers or performing the duties of the Board is final and shall not be questioned, reviewed or restrained by any proceeding in the nature of an application for judicial review or otherwise in any court.

Gas Utilities Act, R.S.A. 2000, c. G-5

Supervision

22(1) The Board shall exercise a general supervision over all gas utilities, and the owners of them, and may make any orders regarding equipment, appliances, extensions of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

(2) The Board shall conduct all inquiries necessary for the obtaining of complete information as to the manner in which owners of gas utilities comply with the law, or as to any other matter or thing within the jurisdiction of the Board under this Act.

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Investigation of gas utility

24(1) The Board, on its own initiative or on the application of a person having an interest, may investigate any matter concerning a gas utility.

...

Designated gas utilities

26(1) The Lieutenant Governor in Council may by regulation designate those owners of gas utilities to which this section and section 27 apply.

(2) No owner of a gas utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of it or them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of it or them,

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and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a gas utility designated under subsection (1) in the ordinary course of the owner's business.

...

Prohibited share transactions

27(1) Unless authorized to do so by an order of the Board, the owner of a gas utility designated under section 26(1) shall not sell or make or permit to be made on its books any transfer of any share or shares of its capital stock to a corporation, however incorporated, if the sale or transfer, by itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the gas utility.

...

Powers of Board

36 The Board, on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges or schedules of them, as well as commutation and other special rates, which shall be imposed, observed and followed afterwards by the owner of the gas utility,

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a gas utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board,

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility,

(d) require an owner of a gas utility to establish, construct, maintain and operate, but in [page217] compliance with this and any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the gas utility reasonably warrants the original expenditure required in making and operating the extension, and

(e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

Rate base

37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

Excess revenues or losses

40 In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the [page218] fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of that period,

(b) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines is just and reasonable,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, that the Board determines has been due to undue delay in the hearing and determining of the matter, and

(d) the Board shall by order approve

(i) the method by which, and

(ii) the period, including any subsequent fiscal period, during which,

any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (b) or (c), is to be used or dealt with.

General powers of Board

59 For the purposes of this Act, the Board has the same powers in respect of the plant, premises, equipment, service and organization for the production, distribution and sale of gas in Alberta, and in respect of the business of an owner of a gas utility and in respect of an owner of a gas utility, that are by the *Public Utilities Board Act* conferred on the Board in the case of a public utility under that Act.

Public Utilities Board Act, R.S.A. 2000, c. P-45

Jurisdiction and powers

36(1) The Board has all the necessary jurisdiction and power

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(a) to deal with public utilities and the owners of them as provided in this Act;

(b) to deal with public utilities and related matters as they concern suburban areas adjacent to a city, as provided in this Act.

(2) In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

(3) The Board has, and is deemed at all times to have had, jurisdiction to fix and settle, on application, the price and terms of purchase by a council of a municipality pursuant to section 47 of the *Municipal Government Act*

(a) before the exercise by the council under that provision of its right to purchase and without binding the council to purchase, or

(b) when an application is made under that provision for the Board's consent to the purchase, before hearing or determining the application for its consent.

General power

37 In matters within its jurisdiction the Board may order and require any person or local authority to do forthwith or within or at a specified time and in any manner prescribed by the Board, so far as it is not inconsistent with this Act or any other Act conferring jurisdiction, any act, matter or thing that the person or local authority is or may be required to do under this Act or under any other general or special Act, and may forbid the doing or continuing of any act, matter or thing that is in contravention of any such Act or of any regulation, rule, order or direction of the Board.

Investigation of utilities and rates

80 When it is made to appear to the Board, on the application of an owner of a public utility or of a municipality or person having an interest, present or contingent, in the matter in respect of which the application is made, that there is reason to believe that the tolls demanded by an owner of a public utility exceed what is just and reasonable, having regard to the nature and quality of the service rendered or of the commodity supplied, the Board

(a) may proceed to hold any investigation that it thinks fit into all matters relating to the nature [page220] and quality of the service or the commodity in question, or to the performance of the service and the tolls or charges demanded for it,

(b) may make any order respecting the improvement of the service or commodity and as to the tolls or charges demanded, that seems to it to be just and reasonable, and

(c) may disallow or change, as it thinks reasonable, any such tolls or charges that, in its opinion, are excessive, unjust or unreasonable or unjustly discriminate between different persons or different municipalities, but subject however to any provisions of any contract existing between the owner of the public utility and a municipality at the time the application is made that the Board considers fair and reasonable.

Supervision by Board

85(1) The Board shall exercise a general supervision over all public utilities, and the owners of them, and may make any orders regarding extension of works or systems, reporting and other matters, that are necessary for the convenience of the public or for the proper carrying out of any contract, charter or franchise involving the use of public property or rights.

...

Investigation of public utility

87(1) The Board may, on its own initiative, or on the application of a person having an interest, investigate any matter concerning a public utility.

(2) When in the opinion of the Board it is necessary to investigate a public utility or the affairs of its owner, the Board shall be given access to and may use any books, documents or records with respect to the public utility and in the possession of any owner of the public utility or municipality or under the control of a board, commission or department of the Government.

(3) A person who directly or indirectly controls the business of an owner of a public utility within Alberta and any company controlled by that person shall give the Board or its agent access to any of the books, documents and records that relate to the business of the owner or shall furnish any information in respect of it required by the Board.

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Fixing of rates

89 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, which is to be made after giving notice to and hearing the parties interested,

(a) fix just and reasonable individual rates, joint rates, tolls or charges, or schedules of them, as well as commutation, mileage or kilometre rate and other special rates, which shall be imposed, observed and followed subsequently by the owner of the public utility;

(b) fix proper and adequate rates and methods of depreciation, amortization or depletion in respect of the property of any owner of a public utility, who shall make the owner's depreciation, amortization or depletion accounts conform to the rates and methods fixed by the Board;

(c) fix just and reasonable standards, classifications, regulations, practices, measurements or service, which shall be furnished, imposed observed and followed subsequently by the owner of the public utility;

(d) repealed;

(e) require an owner of a public utility to establish, construct, maintain and operate, but in compliance with other provisions of this or any other Act relating to it, any reasonable extension of the owner's existing facilities when in the judgment of the Board the extension is reasonable and practical and will furnish sufficient business to justify its construction and maintenance, and when the financial position of the owner of the public utility reasonably warrants the original expenditure required in making and operating the extension.

Determining rate base

90(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed subsequently by an owner of a public utility, the Board shall determine a rate base for the property of the owner of a public utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.

(2) In determining a rate base under this section, the Board shall give due consideration

(a) to the cost of the property when first devoted to public use and to prudent acquisition cost to [page222] the owner of the public utility, less depreciation, amortization or depletion in respect of each, and

(b) to necessary working capital.

(3) In fixing the fair return that an owner of a public utility is entitled to earn on the rate base, the Board shall give due consideration to all those facts that, in the Board's opinion, are relevant.

Revenue and costs considered

91(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed by an owner of a public utility,

(a) the Board may consider all revenues and costs of the owner that are in the Board's opinion applicable to a period consisting of

(i) the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them,

(ii) a subsequent fiscal year of the owner, or

(iii) 2 or more of the fiscal years of the owner referred to in subclauses (i) and (ii) if they are consecutive,

and need not consider the allocation of those revenues and costs to any part of such a period,

(b) the Board shall consider the effect of the *Small Power Research and Development Act* on the revenues and costs of the owner with respect to the generation, transmission and distribution of electric energy,

(c) the Board may give effect to that part of any excess revenue received or any revenue deficiency incurred by the owner that is in the Board's opinion applicable to the whole of the fiscal year of the owner in which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines is just and reasonable,

(d) the Board may give effect to such part of any excess revenue received or any revenue deficiency incurred by the owner after the date on which a proceeding is initiated for the fixing of rates, tolls or charges, or schedules of them, as the Board determines has been due to undue delay in the hearing and determining of the matter, and

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(e) the Board shall by order approve the method by which, and the period (including any subsequent fiscal period) during which, any excess revenue received or any revenue deficiency incurred, as determined pursuant to clause (c) or (d), is to be used or dealt with.

Designated public utilities

101(1) The Lieutenant Governor in Council may by regulation designate those owners of public utilities to which this section and section 102 apply.

(2) No owner of a public utility designated under subsection (1) shall

(a) issue any

(i) of its shares or stock, or

(ii) bonds or other evidences of indebtedness, payable in more than one year from the date of them,

unless it has first satisfied the Board that the proposed issue is to be made in accordance with law and has obtained the approval of the Board for the purposes of the issue and an order of the Board authorizing the issue,

(b) capitalize

(i) its right to exist as a corporation,

(ii) a right, franchise or privilege in excess of the amount actually paid to the Government or a municipality as the consideration for it, exclusive of any tax or annual charge, or

(iii) a contract for consolidation, amalgamation or merger,

(c) without the approval of the Board, capitalize any lease, or

(d) without the approval of the Board,

(i) sell, lease, mortgage or otherwise dispose of or encumber its property, franchises, privileges or rights, or any part of them, or

(ii) merge or consolidate its property, franchises, privileges or rights, or any part of them,

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and a sale, lease, mortgage, disposition, encumbrance, merger or consolidation made in contravention of this clause is void, but nothing in this clause shall be construed to prevent in any way the sale, lease, mortgage, disposition, encumbrance, merger or consolidation of any of the property of an owner of a public utility designated under subsection (1) in the ordinary course of the owner's business.

...

Prohibited share transaction

102(1) Unless authorized to do so by an order of the Board, the owner of a public utility designated under section 101(1) shall not sell or make or permit to be made on its books a transfer of any share of its capital stock to a corporation, however incorporated, if the sale or transfer, in itself or in connection with previous sales or transfers, would result in the vesting in that corporation of more than 50% of the outstanding capital stock of the owner of the public utility.

...

Interpretation Act, R.S.A. 2000, c. I-8

Enactments remedial

10 An enactment shall be construed as being remedial, and shall be given the fair, large and liberal construction and interpretation that best ensures the attainment of its objects.

Solicitors:

Solicitors for the appellant/respondent on cross-appeal: McLennan Ross, Calgary.

Solicitors for the respondent/appellant on cross-appeal: Bennett Jones, Calgary.

Solicitor for the intervener the Alberta Energy and Utilities Board: J. Richard McKee, Calgary.

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Solicitor for the intervener the Ontario Energy Board: Ontario Energy Board, Toronto.

Solicitors for the intervener Enbridge Gas Distribution Inc.: Fraser Milner Casgrain, Toronto.

Solicitors for the intervener Union Gas Limited: Torys, Toronto.

cp/e/qw/qlls

TAB 9

Ontario Energy Board

Ontario

G-2009-0300

Guidelines:

Regulatory and Accounting Treatments for Distributor-Owned Generation Facilities

September 15, 2009

1. Purpose

This document sets out a regulatory framework for the regulatory and accounting requirements for electricity distributors that own and operate renewable energy generation, combined power and thermal (heat) energy generation and energy storage facilities (collectively referred to below as "distributor-owned generation facilities"). This document contains the Board's guidance to electricity distributors in relation to an amendment to the *Ontario Energy Board Act, 1998* (OEB Act) that allows distributors to own and operate such generation facilities. The amendment came into effect when the relevant provisions of the *Green Energy and Green Economy Act, 2009* ("Green Energy Act") came into force.

The purpose of this document is to describe the ownership scenarios potentially available to distributors for generation facilities; and to set out the regulatory and accounting requirements applicable to each scenario.

2. Legal and Regulatory Framework

2.1. The Green Energy Act

On May 14, 2009, the Green Energy Act received Royal Assent. On September 9, 2009, the relevant sections were proclaimed into force and the Green Energy Act amended the OEB Act to address, amongst other things, distributor-owned generation facilities.

The Green Energy Act has amended s. 71 of the OEB Act by adding the following:

(3) Despite subsection (1), a distributor may own and operate,

- (a) a renewable energy generation facility that does not exceed 10 megawatts or such other capacity as may be prescribed by regulation and meets the criteria prescribed by regulation;
- (b) a generation facility that uses technology that produces power and thermal energy from a single source that meets the criteria prescribed by regulation; or
- (c) an energy storage facility that meets the criteria prescribed by regulation.

The Board acknowledges that future regulations and directives may be issued to complement the legislative framework set out in the Green Energy Act. To the extent that such instruments clarify, alter or supplement the subject matter of this document, the Board will reflect these developments in subsequent guidance.

2.2 Legislative Limitation on Rate Regulation

Section 78(3) of the OEB Act only permits the Board to set rates for the transmission and distribution of electricity and for the retailing of electricity. The statutory framework does not currently give the Board the power to include generation assets in rate base, nor to permit rate recovery for any associated operations and maintenance expenses for distributors.

3. Ownership Scenarios for Generation Facilities

This section provides an overview of two potential business scenarios for investment in generation facilities.

The Board recognizes that distributors may not have an immediate need or investment plan to commence projects relating to energy generation facilities given that such projects require analysis, study and planning prior to any decisions being made to undertake such investments. The approach selected will determine the extent of the required regulatory oversight. These optional business scenarios are discussed in sections 3.1 and 3.2.

3.1. Generation Facility Owned by an Affiliate

Affiliates of distributors are currently permitted to own and operate generation facilities; this situation will not be altered by the Green Energy Act. Any new generation facility owned or operated by an affiliate of a distributor would continue to be governed by the current rules, including the requirement for compliance with the Affiliate Relationships Code (ARC) for Electricity Distributor and Transmitters and the requirement to provide notice to the Board under s. 80 of the OEB Act.

3.2. Generation Facility Owned by Distributor and Non-Rate Regulated

A distributor may also choose to own and operate a generation facility directly as part of its utility business. Under this scenario, costs would not be recovered through rates and a regulatory return would not be earned on the investment. The investment project would be debt and/or equity financed. The distributor may enter into a feed-in tariff (FIT) contract with the Ontario Power Authority (OPA). These contracts are long-term in nature and the energy prices vary depending on the type of generation technology and the capacity of the facility.

Like any generator, a distributor that chooses to generate electricity for sale through the IESO administered markets or directly to another person is required to obtain a license from the Board pursuant to s. 57 of the OEB Act. Any distributor that chooses to own or construct generation facilities must also give notice of its proposal to the Board pursuant to s. 80 of the OEB Act.

4. Accounting Requirements

4.1. Generation Facility Owned by a Distributor's Affiliate

Under this ownership scenario, distributors will need only to review its policies, procedures and processes to ensure compliance with the ARC requirements. ARC requirements that the distributor may need to consider include:

- A utility shall ensure accounting and financial separation from all affiliates and shall maintain separate financial records and books of accounts.
- Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate.
- A utility may provide loans, guarantee the indebtedness of, or invest in the securities of an affiliate, but shall not invest or provide guarantees or any other form of financial support if the amount of support or investment, on an aggregated basis over all transactions with all affiliates, would equal an amount greater than 25 percent of the utility's total equity.

The Accounting Procedures Handbook (APH) for Electric Distribution Utilities, Article 340, Allocation of Costs and Transfer Pricing, provides accounting guidance related to the allocation of costs that should be followed by the regulated utility and its affiliates in developing its policies and procedures for allocating the cost of transactions, products or services between the regulated utility and its affiliates[1].

Article 340 also provides that, to the extent possible, all direct and allocable costs between regulated and non-regulated lines of business, services or products shall be traceable on the books of the regulated utility to the Uniform System of Accounts (USoA). Section 2.1.10 of the Electricity Reporting and Record Keeping Requirements ("RRR") contains the current reporting requirements for affiliate arrangements and transactions. In addition, additional documentation shall be retained and made available to the Board upon request regarding transactions between the regulated utility and its affiliates.

4.2. Generation Facility Owned by Distributor and Non-Rate Regulated

Although under this scenario distributor generation activities will not affect the setting of rates for the distributor, the accounting treatment requires a segregation of these activities from the distributor's rate-regulated activities. This segregation of information requires the use of specified accounts to record generation activities. A distributor should follow these accounting procedures to ensure that information reported for rate setting purposes relates only to the distributor's rate-regulated business and does not include the assets, liabilities, revenues and costs associated with its non-rate regulated activities. In this manner, the distributor will continue to provide financial information on a "stand alone" rate-regulated basis in order to support the distribution rate setting and other requirements of the Board.

Appendix A provides a methodology whereby a distributor can allocate direct costs and a proportional share of indirect costs (such as payroll burden) to its non-rate regulated activities including its generation business activities. Adhering to this methodology will ensure that distribution ratepayers are not liable for non-rate regulated costs for which shareholders are responsible.

The distributor should document and maintain records of its fully allocated costing methodology for generation activities, including its application of this methodology to the accounts under the USoA.

For accounting and reporting purposes, the distributor will use the following asset, liability, shareholders' equity, revenue and expense accounts and sub-accounts to record transactions associated with distributor-owned generation facilities.

[1] Although parts of Article 340 of the APH regarding the ARC are currently out of date, the accounting requirements are current.

- Account 2075, Non-Utility Property Owned or Under Capital Leases, Sub-account Generation Facility Assets. Amounts recorded in this account shall include capital assets (property, plant and equipment) and intangible assets. These assets are not included in rate base and the associated amortization expenses are not included in the revenue requirement of the distributor.

- Account 2285, Obligations Under Capital Leases-Current, Sub-account Generation Facility Liabilities. Amounts recorded in this account shall include current liabilities associated with generation. These liabilities shall not be included in the distribution rates.

- Account 2325, Obligations Under Capital Lease-Non-Current, Sub-account Generation Facility Liabilities. Amounts recorded in this account shall include the liability portion not due within one year associated with generation. These liabilities shall not be included in the distribution rates.

- Account 3075, Non-Utility Shareholders' Equity, Sub-account Generation Facilities. This sub-account shall include shares, paid-in capital, appropriated and unappropriated retained earnings, balance transferred from income and dividends associated with distributor-owned generation. Sub-accounts may be used to distinguish the components of non-rate regulated shareholders' equity. Account 3075 is a new account.

- Account 4375, Revenues from Non-Utility Operations, Sub-account Generation Facility Revenues. Amounts recorded in this account shall include revenues for generation from all sources, including Feed-in Tariff contract revenues.

- Account 4380, Expenses from Non-Utility Operations, Sub-account Generation Facility Expenses. Additional accounts shall be used under this sub-account to record the following categories of costs: (1) energy supply expenses (e.g. fuel), (2) operation, (3) maintenance (4) administration, (5) taxes/ payment in lieu (PILs) and (6) amortization expenses.

A distributor may use additional sub-accounts than specified in the above-noted accounts, as necessary to provide full details of the transactions related to distributor-owned generation activities. Accounting information details should be maintained and made readily available to support Board review of these transactions. Further accounting guidance may be provided if necessary.

A distributor is required to file annual audited financial statements under the RRR. The reporting requirements for financial statements in section 2.1.6 of the RRR specify the following:

> "...Where the financial statements of the corporate entity regulated by the Board contain material businesses not regulated by the Board, or where the regulated entity conducts more than one activity regulated by the Board, the distributor shall disclose separately information about each operating segment in accordance with the Segment Disclosure provisions corporate entities are encouraged to adopt by the Canadian Institute of Chartered Accountants Handbook [CICA Handbook]."

Where non-regulated activities including the activities specified in s. 71(3) of the OEB Act are included in the distributor's operations, the distributor should ensure the activities that represent "material businesses" are reported as operating segments consistent with provisions of Section 1701, Segment Disclosures, of CICA Handbook in the distributor's audited financial statements. In addition to the non-regulated activities Including the activities specified in s. 71(3) that may require segment disclosure for financial accounting and reporting purposes, for rate setting purposes, a distributor will need to file financial information in rate applications that clearly delineates the distributor's regulated activities from its non-rate regulated activities. The rate applications should provide a description of the procedures and processes that were used to segregate the accounting information.

Appendix A

Fully Allocated Costing Methodology for Non-Rate Regulated Activities

1. DEFINITIONS

In this Appendix:

"Allocable Costs" means indirect costs (i.e., costs that would be incurred regardless of whether or not the Non-Rate Regulated activities were undertaken);

"Cost Driver" means a measure used to allocate, to a Non-Rate Regulated activity, the costs of any functions performed within the distribution company to undertake that Non-Rate Regulated activity;

"Fully Allocated Costs" means the sum of Marginal Costs and Allocable Costs;

"Marginal Costs" means direct costs (i.e., costs that would be eliminated or reduced if the Non-Rate Regulated Activities were no longer undertaken);

"Non-Rate Regulated Activities" means activities that are carried out by a distributor but not rate-regulated by the Board (e.g., global adjustment mechanism funded CDM Programs, billing and collection services for water and sewage, and distributor-owned generation).

2. COST ALLOCATION PROCESS

2.1 Marginal Costs can be directly assigned to the Non-Rate Regulated activity. Allocable Costs must be allocated, using a Cost Driver, to determine the proportional share of the Allocable Costs attributable to the Non-Rate Regulated activities.

2.2 In order to determine the costs associated with the Non-Rate Regulated Activities, distributors shall use an activity analysis to assess the nature and extent of the functions being performed throughout the distribution company to undertake the Non-Rate Regulated Activities. The analysis must include the identification of all activities performed within the distribution company regardless of whether or not these activities directly or indirectly support the Non-Rate Regulated Activities.

2.3 The activity analysis referred to in section 2.2 must include the following Marginal Costs and Allocable Costs, where applicable:

(a) all salaries and labour costs including benefits;
(b) contractor expenses;
(c) billing and collection;
(d) customer care, marketing and advertising;
(e) administration and general expenses;
(f) IT costs;
(g) office equipment; and
(h) any other cost that the distributor can show is relevant and necessary for the program analysis.

2.4 A distributor must determine an appropriate Cost Driver for each Allocable Cost. Cost Drivers must be:

(a) representative of how costs are being incurred;
(b) implemented in a cost effective manner; and
(c) verifiable and justifiable.

The types of Cost Drivers that distributors may use are included below in sections 2.5 to 2.7.

2.5 Distributors may use headcount as a Cost Driver for the allocation of salaries, other labour related costs, administration and general expenses, and IT costs. This Cost Driver is based on the number of full-time equivalents needed to support the Non-Rate Regulated Activities. Distributors shall calculate full time equivalents in accordance with the following examples:

(a) if six employees each devoted 25% of their time to the Non-Rate Regulated activity, the full-time equivalent for those employees would be 1.5; and
(b) if six part-time employees each devoted 25% of their time to the Non-Rate Regulated activities, the part-time positions would first need to be translated into a full-time position (i.e., if an employee works 3 days per week, the full-time position would be 0.6) and then apply the percentage (i.e., 6 X 0.6 = 3.6 and 25% of 3.6 = 0.9) so the full-time equivalent would be 0.9.

2.6 Distributors may use time as a Cost Driver for the allocation of executive and administrative functions, legal services, and financial analysis because these functions are typically project specific. Distributors shall calculate the percentage of time to be allocated to the Non-Rate Regulated Activities by using the base hours per employee. A distributor shall calculate an employee's base hours by determining the hours that the employee can be considered to be available for work for the period being measured. Distributors shall calculate the percentage of time in accordance with the following example:

(a) if an employee's base hours are 40 hours per week and the employee actually worked 40 hours that week, which included four hours of his/her time spent on a Non-Rate Regulated Activities, the percentage of time allocation would be 10 percent; and
(a) If an employee's base hours are 40 hours per week and the employee actually worked 60 hours that week, which included four hours of his/her time spent on a Non-Rate Regulated Activities, the percentage of time allocation would still be 10 percent.

2.7 Distributors may use the frequency of an activity as a Cost Driver for the allocation of call centre costs and accounts payable processing because these activities can be repetitive in nature and consistent over time in terms of the level of effort required to provide the service. Call centre costs shall be allocated based on number of calls received in relation to the Non-Rate Regulated Activities and accounts payable processing costs shall be allocated based on the number of invoices processed for Non-Rate Regulated Activities.

TAB 10

E.B.O. 179-14
E.B.O. 179-15

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

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for an order or orders approving rates to be charged for the sale, distribution, transmission and storage of gas for its 1999 fiscal year;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for all necessary approvals of transactions related to the transfer of certain customer information systems to an affiliate;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for all necessary approvals of transactions related to the transfer of certain businesses and activities to one or more affiliates;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for approval of an incentive mechanism in relation to the Operation and Maintenance Expense component of its cost of service, effective during the 2000 through 2002 fiscal years, and an incentive mechanism in relation to Demand Side Management.

BEFORE: H.G. Morrison
Presiding Member

P. Vlahos
Member

DECISION WITH REASONS

March 31, 1999

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APPENDICES

1. INTRODUCTION

1.1 THE APPLICATION AND PROCEEDING

1.1.1 The Consumers' Gas Company Ltd. ("Enbridge Consumers Gas" or "the Company") filed an Application with the Ontario Energy Board ("the Board") dated January 8, 1998 ("the Application"), for relief on a number of matters. The details of the application are contained in the Board's Decision with Reasons in E.B.R.O. 497, issued August 30, 1998. The present Proceeding addresses approvals requested by the Company for transactions between itself and an affiliate and for specific regulatory treatment of certain programs.

1.1.2 The procedural framework for this Proceeding was set out in Procedural Order No. 5 issued in October 1998. As a result of this Order, one Proceeding was constituted for the Company's proposed targeted Performance Based Regulation or PBR (E.B.R.O. 497-01) and another for the matters described in this Decision (E.B.O. 179-14 and E.B.O. 179-15).

1.1.3 Procedural Order No. 5 provided for the oral hearing into this matter to commence on December 16, 1998; Procedural Order No. 6 set dates for a technical conference, a settlement conference and the exchange of interrogatories. The Board was advised on December 15, 1998 by the Minister of Energy, Science and Technology that the Government had approved new Undertakings of the Company to be effective March 31, 1999 ("the 1998 Undertakings" or "the new Undertakings"). The 1998 Undertakings superseded the 1994 Undertakings and will be in effect at the time the proposed transactions would take place. While the 1994 Undertakings had required the Board's approval for affiliate transactions and diversification activities of the type proposed, the new Undertakings removed that requirement. Board approval is therefore no longer required for the transfer of ancillary activities to an affiliate, but Board approval is required to retain such activities within the regulated utility.

1.1.4 At the outset of the hearing of the Application on December 16, 1998, the Board requested the Company and intervenors to make submissions on the effect the new Undertakings would have on the Company's Application. Having heard the submissions, the Board requested the Company to consider whether or not it wished to reframe its application in light of the new Undertakings. The Company provided a reframed application on December 18, 1998. This reframed application, as clarified by the Company in its Argument-in-Chief, is set out in detail in the next Chapter.

1.1.5 Having received the reframed application, the Board requested submissions from the Applicant and parties as to the appropriate timetable for continuing the Proceeding and, having received those submissions, the Board issued Procedural Order No. 7 on December 23, 1998. This Procedural Order established a revised issues list and ordered that the oral hearing commence on January 11, 1999. The oral hearing required seven hearing days, concluding on January 25, 1999. The argument phase was completed on March 8, 1999.

1.1.6 Copies of all the evidence, exhibits and argument filed in the Proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices. While the Board has considered all of the evidence and submissions presented in this hearing, the Board has chosen to cite these only to the extent necessary to clarify specific issues on which it has made findings.

1.2 THE SETTLEMENT PROPOSAL

1.2.1 A Settlement Conference for E.B.O. 179-14 and E.B.O. 179-15 was held by the parties commencing November 16, 1998 and resulted in the settlement of only one of the issues, the one related to energy use and demand-side management programs. The settlement of this issue, as set out in the Settlement Proposal is described in Appendix A. The final result of the Settlement Proposal was presented to the Board on December 1, 1998. The settlement was accepted by the Board subject to updates, changes necessary as a result of the Board's Decision on unsettled matters, or as a result of unforeseen events.

1.3 PARTIES TO THE PROCEEDING

1.3.1 Thirty-five parties intervened. Below is a list of parties, including the Company, and their representatives who participated actively in the oral hearing by cross-examining or filing argument.

The Consumers' Gas Company Ltd. ("Enbridge Consumers Gas")	Jerry Farrell Fred Cass
Alliance Gas Management Inc. ("Alliance Gas")	Brian Dingwall

Alliance of Manufacturers and Exporters, Canada ("AMEC")	Beth Symes C. Street
Association of Municipalities of Ontario ("AMO")/ECNG Inc. ("ECNG")	Peter Scully
Coalition for Efficient Energy Distribution ("CEED")	George Vegh Elizabeth DeMarco
Consumers Association of Canada ("CAC")	Robert Warren
Energy Probe Foundation ("Energy Probe")	Mark Mattson
Green Energy Coalition ("GEC")	David Poch
The Heating, Ventilation and Air Conditioning Contractors Coalition Inc. ("HVAC")	Ian Mondrow
Industrial Gas Users Association ("IGUA")	Peter Thompson Bryan Carroll
Ontario Association of Physical Plant Administrators ("OAPPA")	Michael Morrison

Ontario Association of School Board Officials/Metropolitan Toronto Separate School Board ("the Schools")	Thomas Brett
Ontario Coalition Against Poverty ("OCAP")	Michael Janigan Philippa Lawson
Pollution Probe Foundation ("Pollution Probe")	Murray Klippenstein
Union Energy Inc. ("Union Energy")	Donald Rogers
Canadian Association of Energy Service Companies ("CAESCO")	Thomas Brett
Coalition of Eastern Natural Gas Aggregators and Sellers ("CENGAS")	Richard Perdue

1.3.2 In addition, the Board received three letters requesting observer status from other organizations and individuals, and two letters of comment expressing concerns regarding the Company's request to increase rates.

1.3.3 The Enbridge Consumers Gas' employees who appeared as witnesses are shown below.

L.A.E. Beattie	Vice-President, Energy Supply and Storage

R.A. Bourke	Manager, Regulatory Accounting
D. Charleson	Manager, Accounting Systems
G. J. Hills	Vice-President, Regulatory and Legal
J.A. Holder	Vice President, Market Development
W. Lomax	Manager, Financial Studies
R. Rackus	General Manager, Central Region
W. B. Taylor	Director, Financial and Economic Studies

1.3.4 In addition, the Company called the following witnesses:

K. McShane	Vice-President and senior consultant of Foster Associates Inc.

1.3.5 HVAC called the following witnesses:

R. Grochmal	Owner, Atlas Air Conditioning Company and Chair - HVAC Coalition
M. Luymes	Manager, Heating, Refrigeration and Air Conditioning Contractors of Canada ("HRAC"), a division of the Heating Refrigeration and Air Conditioning Institute of Canada ("HRAI")

P. Messenger	President and Owner of Messenger Mechanical Inc. under the trademark of A1 Air Conditioning and Heating

1.3.6 CAC, IGUA, OCAP and HVAC called the following witness:

Dr. J. Bauer	Associate Professor in the Department of Telecommunication, Michigan State University and a Research Associate in the Institute of Public Utilities.

2. THE COMPANY'S PROPOSAL AND PARTIES' VIEWS

2.1 THE ORIGINAL APPLICATION

2.1.1 In its original Application dated January 8, 1998, the Applicant proposed to separate and remove (or unbundle) the following from the existing operations of the regulated utility:

- its Merchandise Sales Program (or Merchandise Business Unit);
- its Heating Parts Replacement Plan or HIP; and
- approximately one half of the service operations currently provided to customers by the regulated utility under its Customer Maintenance Programs and Customer Appliance Repair and Diagnostic Service.

2.1.2 These ancillary services, together with the non-utility Merchandise Finance Program ("MFP") were proposed to be transferred to Consumersfirst Ltd. ("Consumersfirst"), a non-subsidiary affiliate of the Company, on October 1, 1999. The Company's proposal would result in Consumersfirst operating the transferred businesses outside of regulation. The Company proposed that its Natural Gas Vehicle Program ("NGV") and its rental program remain within the regulated utility, although it proposed to wind-down its rental program gradually.

2.1.3 As part of its Application, the Company requested the establishment of an Unbundling Business Activities Deferral Account to record costs incurred in the 1998 and 1999 fiscal years in relation to the transfers proposed. In addition, the Company requested approval of the Board for the ratemaking implications of its proposals relating to the rental program, including approval for the recovery from ratepayers of unrecorded deferred income taxes in relation to the program. This original Application was framed under the 1994 Undertakings.

2.2 THE REFRAMED APPLICATION

2.2.1 As noted in Chapter 1, the Board was advised that the 1998 Undertakings would supersede the 1994 Undertakings. While the 1994 Undertakings had required the Board's approval for affiliate transactions and diversification activities of the type proposed, the new Undertakings removed that requirement, replacing it with the following:

> *Consumers shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.* (Article 2.1)

2.2.2 The reframed Application, under the new Undertakings, as clarified during the hearing, was described by the Applicant in its Argument-in-Chief as follows:

The Company requests that the Board grant the following under Article 2.1 of the 1998 Undertakings:

- *prior approval for the Company to carry on the business activity known as the Rental Program, in a wind-down mode, on and after October 1, 1999* *until the wind-down is completed, including the Rental Service Agreement with Consumersfirst Ltd. during the initial five years; and*

- *prior approval for the Company to carry on the business activity known as the ABC-T Program, in its current format, on and after October 1, 1999 and until the Board determines that the program should be discontinued.*

The Company also requests that the Board approve the following for rate-making purposes:

- *an Unbundling Business Activities Deferral Account in order to record and recover reasonably incurred costs, in the 1998, 1999, and 2000 fiscal years, in relation to the transfer, by the Company to Consumersfirst Ltd., of the assets that comprise, and of copies of the information software that is necessary to operate, the following businesses and activities: merchandise sales, heating parts replacement plan (also known as "HIP"), and certain service activities;*

- *the proposed regulatory treatment of the Rental Program in a wind-down mode, including the following:*
  - *the classification of the program as a core utility activity; and*
  - *the recovery from ratepayers, in due course on a taxes payable or "flow through" basis, of the Company's unrecorded deferred income tax liability in relation to the program as at September 30, 1999 (approximately $168.2 million), to the extent that such liability cannot be recovered from customers of the program; and*

- *the proposed Unbundled Budget for use in connection with the targeted Performance Based Regulation (PBR) plan that is before the Board in the E.B.R.O. 497-01 proceeding.*

2.2.3 The retention of other programs, including NGV, within the utility from March 31, 1999 until the end of the fiscal year was requested by letter to the Board dated December 17, 1998. These requests have been approved by the Board in a letter dated March 24, 1999.

2.3 TRANSFERRED OUT PROGRAMS

2.3.1 The Company plans to transfer assets with a net book value of approximately $166.8 million to its affiliate, Consumersfirst, of which $140.7 million are receivables associated with the MFP, and the remaining $26.1 million consists of assets relating to the other programs. To ensure no tax payments are triggered by the transaction, the Company and Consumersfirst would elect under the *Income Tax Act* to transfer the assets, which have been assessed by KPMG as having a fair market value of $168.5 million, at book value. In return for the transfer of the assets, the Company would receive $166.8 million in cash and $1.7 million in preferred shares issued by Consumersfirst. These shares are expected to be redeemed for $1.7 million in cash immediately following the asset transfer.

2.3.2 The Company proposes to continue a management services agreement with Consumersfirst, the fully allocated cost of which is forecast to be $2.4 million annually following the transfer. The Company filed a set of Standards of Business Practice to apply to these activities. These Standards have been preempted subsequently by the Board's draft *Affiliate Relationships Code for Gas Utilities*.

2.3.3 Given that no Board approval is required for these transfers under the new Undertakings, it was not necessary to examine the valuations in detail. Any ratemaking implications will be subject to review in the next main rates case. As noted later in this Decision the Board accepts for removal from the cost of service the amounts identified, as adjusted to reflect the actual amounts at the date of transfer.

2.4 RETENTION OF THE ABC-T PROGRAM

2.4.1 The Company is requesting approval under the new Undertakings to continue the ABC-T Program as an ancillary program within the Utility on the basis of fully allocated costs. The evidence is that this optional billing and collection service provided by the Company to agents, marketers, and brokers is needed in the developing competitive retail natural gas commodity market, and that other alternatives are not yet available. It is the Company's expectation that "the fate of the program would be revisited in another regulatory proceeding before the program would disappear".

2.5 PROPOSED TREATMENT OF THE RENTAL PROGRAM

2.5.1 The Company's rental program currently serves approximately 1.2 million homes and businesses in the Company's franchise area. The Company proposed to wind-down this program, installing no new rental units after October 1, 1999, and replacing no existing rental units at the end of their useful lives. The Company proposed that the rental program would, during the wind-down, cease to be considered an ancillary program and become part of the core utility for regulatory purposes.

Rationale and Proposed Regulatory Treatment

2.5.2 The rental program was operated on a marginal cost basis until the Board's finding in E.B.R.O. 495 required fully allocated costing of the Company's ancillary programs. The Company's proposal to treat this program as part of the core utility would subsume the costs of the program into the utility's cost of service.

2.5.3 In its evidence in E.B.R.O. 497 the Company described the new competitive environment relating to rentals and the difficulties facing the rental program as competitors expand into the business of providing water heaters for sale, and promoting electric water heaters. Essentially, in that Proceeding, the Company requested an extension of the time during which it could operate its rental program on a marginal cost basis. Having not had its request granted, the Company wishes to withdraw from the rental business, and proposes the wind-down as a way to manage the transition.

2.5.4 It was the Company's view that, given the historic benefits it identified with the rental program, its anticipated lack of flexibility to manage revenues and mitigate the impact of premature equipment removals, the loss of economies of scale during the wind-down, and the aim of fostering competition, the rental investment should be treated as any other utility investment through the wind-down. The program would not, under the Company's proposal, be subject to fully allocated costs for regulatory purposes. Until the competitive infrastructure is in place to assure adequate service levels for rental customers, the Company proposes to enter into a five year service agreement with Consumersfirst; at the end of the term of this agreement, the Company states that Consumersfirst would have to compete for the utility business.

2.5.5 It is the Company's view that its wind-down strategy balances the interest of the shareholder in protection of its investment with the interests of customers in increased choice through an orderly transition to competitive markets. Existing customers may remain on the utility rental program until their equipment needs to be replaced, and will be made aware of alternative supply sources. The shareholder would, under the Company's proposal, recover the full costs of winding down the program.

2.6 DEFERRED TAXES

2.6.1 As a result of the Company's use of a "flow through" method of recording taxes relating not only to its regulated utility income but also to the income from the Rental Program, there would be unrecorded deferred taxes in the amount of $168.2 million attributable to rental assets as at the end of fiscal 1999. The Company proposed that ratepayers be responsible for the payment of these deferred taxes. In support of this proposal, the Company cites an analysis of the regulatory treatment of returns on ancillary programs over the past 10 years that indicated a resulting $151 million, on a current dollar basis, benefit to ratepayers over those years, $127.5 million of which is attributable to the rental program. Over the past 20 years, the Company estimated that the rental program had been responsible for approximately $172.5 million in current dollar benefits to ratepayers resulting from the regulatory treatment applied to earnings from it.

2.6.2 As a result of a recent Supreme Court Decision, Revenue Canada has changed the tax treatment of certain expenses associated with rental equipment. Because of this change, the Company was credited with $42 million of tax overpayment. This amount contributed to the total of $168.2 million deferred tax liability noted above. The Company proposed to credit the $42 million to the ratepayers conditional upon the Board accepting the Company's proposed wind-down and deferred tax treatment.

2.7 CONSUMERSFIRST SERVICE AGREEMENT

2.7.1 As noted above, the Company proposes to enter into a five year rental service agreement with Consumersfirst for the latter to provide service to existing rental products primarily consisting of rental water heaters. It is the Company's evidence that its affiliate is the only contractor capable of providing service comparable to that presently provided. At the end of the five year period, other contractors who can demonstrate the capability will be considered to provide this service. The Company contended that this agreement, as opposed to servicing through third parties, will prevent premature stranding of rental assets, because the two companies are commonly owned. The Company also argued that the contract will enable a smooth transition to a competitive market.

2.7.2 Based on a negotiated cost per unit serviced, the Company forecast that it will pay Consumersfirst $17.7 million in fiscal year 2000 to provide the rental equipment service. The Company stated that in its negotiations with Consumersfirst it undertook to ensure that the cost of the agreement would be equivalent to the cost of a Company-managed option using 100% contractor workforce. The Company's evidence indicated that the cost of the rental service agreement on a marginal cost basis is comparable to the cost of a Company-managed alternative.

2.8 STRANDED ASSETS

2.8.1 Assets no longer required for the operation of the core utility once the unbundling process is complete and therefore no longer "used and useful" were estimated at $400,000 after mitigation efforts by the Company. These assets comprise the net cost of telecommunication equipment and infrastructure costs associated with office space reductions. The Company proposed that the stranded costs from these assets be recoverable from ratepayers through depreciation.

2.9 TRANSITION COSTS

2.9.1 The Company identified one-time transition costs of approximately $18.4 million in O&M expenses, and approximately $0.9 million in capital costs. The following table indicates the sources of these costs:

Item	**O&M ($000's)**	**Capital ($000's)**
Customer Communications	900	
System Modifications, Data Extraction	5,000	
Human Resources/Employee Support	4,000	
Office Relocation/Facility Restoration	3,600	900
Consulting & Regulatory Costs	2,100	
Transition Planning	2,800	
	18,400	900
From Prefiled Evidence E.B.R.O. 497-01, E.B.O. 179-14 and 15 Table B/5.3/2		

2.9.2 Costs related to system modifications are claimed to be necessary to ensure appropriate confidentiality of data and continued effective information technology for the core utility. Human resources costs include employee education, relocation, and severance, and the separation of pension and benefit plans for transferred employees. Office relocation and facility restoration expenses involve distributing the utility workforce into facilities owned by the utility, and vacating the leased facilities presently used by the larger bundled operation. Consulting and regulatory costs include costs to obtain independent valuations, tax, legal and accounting opinions and rulings, and the regulatory costs associated with this Application. Transition planning costs are for incremental staff and external consultants to develop and implement transition initiatives.

2.9.3 The Company recommended that, given that the costs associated with unbundling are estimated, a deferral account be set up to capture incremental one-time transition costs so that actual costs related to the planning and implementation of the unbundling proposal become part of the cost of service to be recovered in rates over a three year period from fiscal 2000 to fiscal 2002, inclusive.

2.10 THE UNBUNDLED BUDGET

2.10.1 The Unbundled Budget as presented by the Company is the budget that would have been required for fiscal 1999 had the proposed unbundling of ancillary and service activities been effective on October 1, 1998, representing "the revenue requirement...to operate a core utility, on a stand alone basis (including the Rental Service Agreement), and to provide limited shared services". The Company submitted that the Unbundled Budget demonstrates that the core utility "can deliver annually, on an ongoing basis, some $18.4 million in benefits, or savings, when measured against the revenue requirement of an integrated utility based on the Board-approved budget for fiscal 1999".

2.10.2 It is the Company's position that these savings require not only the removal of the direct costs of the activities proposed to be unbundled, but the incurrence of other management initiatives and efforts which will result in the transition costs noted above.

2.11 PARTIES' VIEWS

2.11.1 The parties, with few exceptions, opposed the Company's proposals in whole or in part. Some noted that the onus was on the Applicant to satisfy the Board that the specific relief it was seeking should be granted, and that the Board could simply turn down the proposal entirely, if that onus was not met. The relief sought was characterized variously as "regulatory overreach", "excessive", and self-serving. Concerns were expressed that the Company was relitigating matters which the Board had clearly determined in previous proceedings, that there were no efficiency gains resulting from its restructuring, and that its proposed contract with its affiliate would distort markets and hinder competition. A number of parties pointed out that the shareholder had chosen to pursue ancillary programs for its own purposes, and must therefore accept the risks of a changing marketplace. Many argued that past benefits were overstated, and some submitted that past outcomes should not, in any case, necessarily determine the fate of the present Application.

2.11.2 There was general support, with one exception, of the Company's proposal to retain ABC-T Service.

2.11.3 With respect to the new Undertakings, parties suggested various tests that might be applied in determining whether business activities other than distribution, transmission and storage of gas should be permitted within the Company, and urged the Board to consider the context of the new legislation, its general purposes, the Board objectives set out in the legislation, the description of the purposes of the new Undertakings and their specific wording, and the general direction of change in the energy industry. Based on Dr. Bauer's testimony, parties urged the Board, at a minimum, to hold ratepayers harmless and apply the test of economic efficiency as a criterion in assessing the Company's requests.

2.11.4 Many parties noted that the Company had provided little in the way of evaluation of alternatives to its proposals. With respect to the deferred taxes, some parties questioned the jurisdiction of the Board to pass through into rates taxes relating to assets of ancillary programs. No party agreed that the "regulatory compact", as articulated by the Company's witness, Ms. McShane, guaranteed recovery of deferred taxes by the shareholder as suggested by the Company. One party suggested that the Board may have been "mistaken" in its past decisions relating to the treatment of taxes, but that it could redeem itself through the proper determination of the present application.

2.11.5 With respect to the proposed services contract with Consumersfirst, there were general concerns that the contract in essence amounted to a transfer of the rental program to the affiliate at no cost, and that in fact the Company would be paying its affiliate to acquire a profitable business as the Company wound down its participation. Evidence provided by witnesses on behalf of HVAC addressed concerns relating to fairness to others in the service industry, and protection of ratepayers from subsidizing an affiliate's entry into the market. Parties recommended that the Board consider these in evaluating the proposal.

2.11.6 A number of parties noted the complexity and difficulty of the issues in the Application. Although there was almost universal agreement that the Company's course should not be agreed to, parties did not generally provide alternative courses for the Board's consideration.

2.11.7 In reply, the Company urged the Board to take a narrower approach to its mandate in relation to competition than that argued for by some parties, noting that the new legislation speaks of the Board's role in facilitating competition in "the sale of natural gas" and in "the generation and sale of electricity". On the other hand, the Company dismissed as "astonishing" any suggestion that the Board does not have the jurisdiction to require ratepayers to pay the deferred tax liabilities. The Company urged the Board to adopt a "just and reasonable" standard in determining the extent to which ratepayers' and shareholders' interests should be protected, a standard it submited would be completely consistent with its proposals with respect to the treatment of the ancillary programs, and the deferred taxes.

3. BOARD FINDINGS

3.1 GENERAL

3.1.1 The Company wishes to retain the rental program within the core utility, wind it down, recover the resulting deferred tax liability from the ratepayers (to the extent that it cannot be recovered from the rental customers) and utilize an exclusive five year service agreement with its affiliate to provide service of the rental assets. The Company also requests approval to retain its ABC-T program within the utility. Additional approvals are sought relating to the costs of transferring other activities out of the utility and the resulting "unbundled budget" for use in connection with a proposed PBR Application that is under consideration by this Board in a related proceeding.

3.1.2 Thus summarized, the Company's proposals seem straightforward. As many intervenors have indicated, however, the matters under consideration in this Application are not only complex, but interwoven in complicated ways. In addition, the consequences are potentially momentous, in both policy and financial terms. It is necessary to carefully balance the interests of ratepayers, shareholders, and users of the programs in question, to consider the changing legislative, regulatory and market contexts, and to take into account previous Board findings and directives.

3.1.3 During the hearing the Board requested clarification from the Company of its expectations should the Board deny part or all of the relief requested. In its Argument-in-Chief, the Company responded, asking for "detailed guidance as to the Board's expectations...[to] enable the Company [if necessary] to design an alternative that would meet the Board's expectations and...facilitate the regulatory process." In setting out its findings in the following pages, the Board has been mindful of the effort that has gone into this Application by all involved, and of the need for regulatory efficiency to utilize that effort to move forward. While some intervenors have urged the Board to "just say no", this course appears to the Board to be wasteful. The Board has therefore attempted to craft a solution to address its concerns with the Application as proposed, and to provide the Company with sufficient information and guidance to allow it to make effective decisions about the way in which it will proceed. The Board has also, of course, addressed the separate requests for approval for transactions other than those relating to the rental program and the resulting deferred tax liability.

3.2 THE RENTAL PROGRAM

Retention Within the "Core Utility"

3.2.1 As noted earlier, the 1998 Undertakings changed the nature of the approvals required by this Board in relation to the Company's activities. The relevant paragraph of the Undertakings reads as follows:

> *Consumers shall not, except through an affiliate or affiliates, carry on any business activity other than the transmission, distribution or storage of gas, without the prior approval of the Board.*

3.2.2 The Board has no difficulty in accepting that the rental program is a "business activity" within the meaning of this paragraph, and the Company does not contend, nor does the Board accept, that the program is part of "the transmission, distribution or storage of gas". Had this been the Company's interpretation, it would not have seen the necessity for approval to retain the rental program.

3.2.3 The Board has reviewed the various positions of the Company and intervenors as to the Board's jurisdiction and role under the *Energy Competition Act*, the direction of policy change envisioned by the new legislation, and the extent to which the gas and electricity sectors must be treated identically or symmetrically. The provisions of the legislation relating to the two sectors are not the same, and while the Board accepts the need for a consistent regulatory approach, it is required under the new Undertakings to make determinations which have no equivalent in relation to the electricity utilities. These decisions must be informed by regulatory history and the Board's sense of the regulatory future. In this particular case, the Board finds that under certain circumstances the carrying on of the business activity of equipment rentals by the Company would be appropriate.

3.2.4 The Board is not prepared, however, to approve a proposal to run the rental program as part of the "core utility". The essence of such a proposal is that no separate costing of the program, and hence no assessment of its profitability is possible. Not only would the costs of the program not be assessed on a fully allocated basis, as the Board has previously directed, but there would be no way of assessing them at all. The extent of any cross subsidization by the ratepayers would be unknown, and there would be little incentive for the Company to operate the program as efficiently as possible. The Board notes as well that any stranded assets which might develop in the program would become a ratepayer responsibility.

3.2.5 The Board's finding with respect to retention of the rental program in the core utility is supported by its view of current regulatory policy, which encourages the development of a "pure utility", stripped of non-monopoly services. The Board recognizes that the issue of the rental programs within the electrical utilities is still under consideration. In the event that such programs are to remain in electrical utilities, the Board will need to apply consistent principles to their regulation. While it may not be necessary to follow the same timetable in the gas industry as may be envisioned for the electric utilities, the general principles with respect to costing of such programs should be the same. Retaining the Company's rental program in the core utility does not allow appropriate costing principles to prevail.

3.2.6 The Board would accept the program, for the time being, on a non-utility basis within the Company, with elimination of the program's costs on a fully allocated basis.

The Proposal to Wind Down the Program

3.2.7 The Company has stated that it does not wish to continue the rental program as a going concern, partly because it is unprofitable to do so under fully allocated costs. While the Company provided, in a transcript undertaking response, a "high-level summary" of its analysis of options leading it to conclude that its proposal was optimum, the Board was not provided with detailed information on options and their consequences. It is clear that "a key component" of the wind-down proposal is the proposed five year service agreement with Consumersfirst. It is also clear that in the Company's view the deferred tax implications of the wind-down proposal were preferable to those that would result from other options.

3.2.8 Whatever the Company's motivation in proposing the wind-down of the rental program, the Board is not convinced that it is either necessary, or the best solution in the circumstances. There is no convincing evidence on the record that competition is rapidly eroding the program's remarkably high market penetration. While according to the Company the program was not forecast to return the allowed rate of return for fiscal 1999, this was partly due to the Company's reclassification of certain diagnostic charges which resulted in additional direct costs of $3.1 million for the program, and additional allocated costs of $6.8 million. Reversal of the changes in accounting for diagnostic charges would have resulted in a forecast combined rate of return of 8.7% for the Company's four ancillary programs, most of which is attributable to the rental program. Even when the program does not yield the returns realized by the utility as a whole, it is not losing money, on any cost allocation basis.

3.2.9 The most important consequence of the fate of the rental program is the timing by which the deferred taxes associated with it must be either recorded or paid. The Board discusses this consequence below. While it is not appropriate for the Board to tell the Company what it should do with the rental program, the Board's proposed treatment of the deferred taxes will determine the parameters within which the Company must decide the fate of the program. If the Company does not wish to continue the program as a non-utility program, it does not need Board approval to transfer it to an affiliate or to sell it to a third party.

3.3 DEFERRED TAX LIABILITY

3.3.1 As noted earlier, approximately $168 million in deferred taxes are associated with the rental program, including a tax credit of some $42 million arising from the recent reversal of Revenue Canada's treatment of expenses associated with the installation of rental assets. In the Board's view, whoever is responsible for the payment of the deferred taxes should be entitled to this credit.

3.3.2 The Company has contended that the deferred tax liability is a ratepayer responsibility, arguing that ratepayers have benefitted from the deferral of the taxes through lower rates, and that there has been a cumulative shortfall in earnings flowing to the shareholder over the years as a result of the lower actual returns from the program. Intervenors have presented various reasons why the liability should not fall on ratepayers.

3.3.3 The Company relies heavily on earlier Board decisions and the "regulatory compact" for its contention that the deferred taxes should be recovered in rates. According to the Company, the Board's decisions and the consequential regulatory precedents imply, without question, a commitment ("the Commitment") that these taxes would be recovered in rates when they are due and payable in the future. The trade-off for this Commitment is that gas rates have been minimized for the many years leading up to the time when the future tax liability arrives.

3.3.4 A review of the history of the Board's considerations of the Company's tax methodology will be helpful in assessing the Company's argument in this respect.

<u>History</u>

3.3.5 The flow through or "taxes payable" method of recording taxes is an exception to the standards of the Canadian Institute of Chartered Accountants ("CICA") as expressed in the following excerpt from the current CICA Handbook:

...the taxes payable basis would be appropriate ... provided that there is a reasonable expectation that all taxes payable in future years will be:
(a) included in the approved rate or formula for reimbursement <u>and</u>
(b) recoverable from the customer at that time.

3.3.6 The CICA Handbook, in setting out this exception to the usual rule that "the deferral method of income tax allocation should be used", notes that the exception would apply in very limited circumstances, and uses as an example of those circumstances "a company in the regulated utility field under the jurisdiction of an authority, which allows as an element of cost in setting rates <u>only</u> the amount of taxes currently payable".

3.3.7 The Company has used the flow through basis of recording its taxes for many years. The Board has reviewed the history of the treatment of taxes, as set out in the cases relied upon by the Company, and notes the following:

- In 1961, when the Company asked the Board to approve an amount in rates for deferred taxes relating to "plant expansion and replacement", the Board declined, citing uncertainty as to when or whether the Company would have to actually pay the taxes in question.
- The Company based a 1975 request for "interim rate relief" to collect deferred taxes in part on the improvement that would result in its "cash flow and financing ability", and cited risks which arose from postponing recovery of taxes.
- One of the reasons recovery of deferred taxes in rates was denied by the Board in the past was that adding to rates for the purpose requested was inconsistent with Government price restraint policies in place at the time to deal with high rates of inflation.
- More than ten years ago Board staff argued for the exclusion of the rental program from the utility operation; at the time, the deferred tax situation was not raised, although evidence filed in the present application suggests that a total unrecorded deferred tax liability of almost $250 million existed at that time, a significant portion of which would have related to rental assets.

- In the past five years, the regulatory treatment of the ancillary programs has been examined in each main rates case; the Board ordered the implementation of fully allocated costing for these programs in 1997.

3.3.8 In E.B.R.O. 497, the Company presented evidence that, on the fully allocated costing basis directed by the Board the previous year, the ancillary programs were forecast to produce a revenue deficiency of $21.3 million dollars. The Company requested that the Board not impute any revenues to the programs in the test year, essentially requesting relief from the application of full costing for the test year. Detailed probing during the hearing revealed that much of the forecast deficiency in these programs could be traced to the introduction by the Company of a separate charge for diagnostic services, and a charging to the ancillary programs of direct and allocable costs related to these services. When these costs were excluded, the forecast revenue deficiency for the programs was reduced to $3.7 million.

3.3.9 The Board expressed its concern in the E.B.R.O. 497 Decision that the costs relating to diagnostic services had not been identified previously in the fully allocated costs study which had been presented to the Board in E.B.R.O. 495. The result of this failure was that the true revenue deficiency of the programs in fiscal 1998 was not recognized, and the Company had, in effect, a transition period in which fully allocated costing did not apply to the programs. The Board declined to provide any additional transition period, and directed that full costing continue to be applied. In addition, the Board expressed its concern as to "what *other* costs properly belonging to either ancillary or non-utility activities are still missing in the Company's cost allocation". It now appears that the unrecorded deferred taxes relating to the ancillary programs were another such cost, and a large one.

The Commitment

3.3.10 The Board does not accept the Company's argument that its past decisions imply the Commitment claimed for the following reasons:

- Many of the Board's decisions addressed whether deferred taxes should be collected in rates of the year in question. No distinction was made between the utility in general and its ancillary programs, although it is noteworthy that aspects of the Company's business, such as exploration and development, were treated differently. These decisions were based on circumstances at the time in question, such as the existence of high inflation, the status of the Company's cash flow and financing capabilities, and the extent to which the Board was persuaded that the Company's future was at risk from competition with other forms of energy or a future shortage of natural gas.
- Some of the decisions dealt with the extent to which a return should be allowed on the deferred taxes, not on a change to the tax methodology itself.
- The Company relies in the present Application on the Board's conclusion in 1976. In that Decision, the Board's statement that "...it is not reasonable to expect that the Applicant would be unable to obtain regulatory approval for the collection of deferred taxes in rates when they become payable, or that competition with other forms of energy would prevent the collection in rates due to a loss of customers" was in response to a Company argument that a future shortage of gas or competition with other energy forms might affect the Company's ability to recover the taxes following the crossover point.
- Where the decision requested was for a change in principle from flow through tax accounting to normalized accounting, the Board relied on its earlier decisions, and did not address the principle.

- The "regulatory compact" does not operate in such a way as to prevent the Board from considering new circumstances and changing its approach in response to them.
- The Company argues that the rental program has always been treated as part of the utility. The Board has never set rental rates, and has always required separate reporting for the ancillary programs. Taxes paid on income from the programs were expected to be part of the expenses directly assigned to the programs. While rates were set on the basis of a forecast rate of return from the rental program which took into account the taxes payable, it is not entirely clear to the Board that the CICA guideline applied to the program at all. Certainly once full costing of the rental program was required, it is difficult to see how the CICA guideline applied. The point was never raised before the Board.
- Even if one accepts that earlier Board decisions did not differentiate between taxes relating to ancillary programs and taxes relating to the utility, it is remarkable that the Company did not alert the Board to the deferred tax problem when the question of the costing of the ancillary programs was under consideration. The Company was undoubtedly aware of the unrecorded deferred tax liability related to these programs. It appears to the Board that its existence was an essential piece of information that should have been available to the Board in its review of the regulatory treatment of these programs. Consideration of a different costing treatment for the rental program commenced as early as 1995 (E.B.R.O. 490). Indeed, in E.B.R.O. 497, the Board expressed its concern "as to what other costs properly belonging to either ancillary or non-utility activities are still missing in the Company's cost allocation". It is notable that the amount of the liability related to the rental program has increased by approximately $50 million dollars since 1995, a period in which there has been considerable discussion of the characterization of costs relating to this program.

3.3.11 Considering all of the above, it is the Board's view that the deferred taxes associated with the rental program should be the responsibility of the shareholder. In the circumstances, the Board does not need to decide whether it has the jurisdiction to pass these costs directly through to the ratepayer in rates. As noted above, the $42 million credit for tax overpayment should, therefore, be credited to the shareholder.

Ratepayer Savings

3.3.12 It is instructive to consider who would have paid the taxes related to the rental program had they not been deferred. The Company's evidence is that rental rates were set by the market, and were not therefore dependent on the program costs. If one accepts that evidence, it follows that the renters would not have paid any more or less had the taxes not been deferred.

3.3.13 The Board cannot accept the Company's premise that rental rates were in fact set by the market as the Company states. The rental business, while competing to some extent with similar programs run by the electricity utilities, was in some senses a "monopoly business", with an approximately 95% market share in the Company's franchise area. Unfortunately, there is no evidence to suggest what differential existed between rental prices as set by the Company and those that would have been determined by the market. To the extent that prices were set to cover costs of the program, renters would have been responsible for paying the taxes, and would have benefitted from their deferral. The Board can only assume that there was some benefit; it cannot be quantified.

3.3.14 In order to analyze who else would benefit from the deferral, or, in other words, who else would have paid the taxes had they not been deferred, it is useful to accept for the purposes of the analysis that rental prices were set by the market, and thereby exclude possible benefits to renters from the analysis for the moment.

3.3.15 For most of the life of the rental program, its costs have been determined on a marginal basis. If one assumes that the taxes on the income of the rental program were charged to the program *as a direct charge*, and that the tax shelter related to the rental assets was applied directly to those taxes, the treatment of the taxes would have been the same under either marginal or fully allocated costing, since direct charges are attributed to the program under either regime. The deferral of the taxes would have, in any given year, lowered the cost of the program. Who benefitted from that lower cost?

3.3.16 To answer this question, it is necessary to note that the setting of utility rates on a forecast basis has the following results:

- if the forecast rate of return for the rental program was higher than the overall allowed rate of return, utility rates would have been set to reflect the higher return from the program, and ratepayers would have benefitted;
- to the extent that the actual rate of return for the program was higher than that forecast, shareholders would have benefitted; and
- to the extent that the actual rate of return was lower than that forecast, the risk being symmetrical, the shareholder would have absorbed the shortfall.

3.3.17 The Company has provided forecast and actual returns over the last ten years. From these, the following can be established:

- On a forecast basis, between 1989 and 1998 there was a total sufficiency from the program of $50 million.
- There are also some benefits to ratepayers from the reduction of fixed costs through incremental gas sales attributable to the rental program and the improvement in system load factor. Although these benefits would also have arisen if the rental program were owned and operated by a third party, it seems unlikely that the high market penetration the program achieved would have occurred had the utility not operated the program. In addition, it should be noted that rental customers are also ratepayers; almost 95% of ratepayers are also renters. To the extent that renters, who are also ratepayers, have not paid higher rental rates to cover costs of the program, they have benefitted.

3.3.18 It is not, in the Board's view, fair to revisit earlier regulatory treatment which allowed the program to operate on a marginal cost basis and calculate for this period a 'subsidy' to the rental program from the general body of ratepayers. The regulatory regime was what it was. However, even if such consideration were justified, the evidence reveals such 'subsidy' is only a portion of the $50 million sufficiency noted above.

3.3.19 It therefore appears to the Board that utility ratepayers have benefitted from the rental program over the years, and that the shareholder has absorbed some costs. While finding that ratepayers should not be responsible for the deferred tax liability, *per se*, related to the rental program, the Board believes that there should be some recognition of the benefits they have received in the past. The Board therefore would accept the provision of a notional utility account in the amount of $50 million, after tax, to allow the shareholder to use the value of these past ratepayer benefits to pay a portion of the deferred taxes associated with the rental program as they become due. It is up to the Company to determine the future of the program, but whatever that choice, the notional account can be drawn down to pay deferred taxes up to $50 million.

3.3.20 There are a number of options which the Company may consider with respect to the rental program, each with its own consequences for the rate at which the deferred taxes will come due. The options include:

- The Company may choose to continue to operate the program as a non-utility program for the time being. As the taxes become due, they will be accounted for as costs for potential elimination as non-utility expenses, as they are not common costs. It is possible that the deferred tax liability would need to be recorded immediately, even though payment is not immediately required.
- The Company may choose to wind-down the program as a non-utility program. In this case, the necessity to pay the deferred taxes will be accelerated.
- The Company may choose to transfer the assets to an affiliate or sell the program to a third party. In these circumstances, any proceeds from the sale or transfer would be available to address the related tax consequences. To the extent that the Company proposes to utilize any or all of the notional account as well, the Board's approval of the ratemaking consequences would be required. The Company should be aware that, under this option, consideration of 'rate shock' may dictate the degree of amortization of the amount to be reflected in rates going forward.

3.3.21 In any of these cases, the Company may draw on the notional account to pay deferred taxes as they become due. If the Company decides to continue the program, it will have an incentive to run it as efficiently as possible, since it must account for it on a fully costed basis. In any year, the amount used from the account would be recognized in rates, subject to considerations of 'rate shock' as noted above.

3.4 CONSUMERSFIRST CONTRACT

3.4.1 The Company has described its proposed contract with Consumersfirst as a "key component of the Company's proposal to wind-down its Rental Program...." Given the Board's findings above, the Company may decide on a different course for the program, and change its approach to service provision. The Board has determined that the program must operate, if it is to be retained by the Company, on the basis of fully allocated costs. Included in these costs will be whatever charges are paid through contracts for service. If the Company is to contract with its affiliate, it will be required to adhere to the *Affiliate Relationships Code for Gas Utilities*, which is intended to address not only the possibility of cross subsidies, but also potential unfair competition by the affiliate with others in similar markets.

3.5 RETENTION OF ABC-T SERVICE PROGRAM

3.5.1 The Board confirmed the status of the ABC-T service as an ancillary program in E.B.R.O. 495, and accepts that it is a "business activity" within the meaning of the 1998 Undertakings. Under fully allocated costing, costs of the program will not be borne by ratepayers. The Board is prepared to accept the retention of the ABC-T Service Program, noting that the Company may decide in the future that the program is no longer economic, and would then be at liberty to cease to operate it. However, for consistency with the Board's findings in relation to the rental program and for regulatory efficiency, the ABC-T Service Program is accepted as non-utility rather than ancillary. Therefore, the Board's review in future will be limited to the costs removed and would not include matters of pricing or profitability.

3.6 TRANSITION COSTS

3.6.1 Of the $18.4 million O&M and $900,000 capital costs that the Company has identified as transition costs in relation to its application, some are directly related to the transfer of assets to Consumersfirst for which the Board's approval was sought in the original application, some arise from the wind-down of the rental program and the remainder relate to the realization of future savings through the reduction of 173 employee positions. No breakdown of these amounts was provided.

3.6.2 Disposition to the ratepayer of the portion of transition costs relating to the transferred programs would reduce the net transfer value of the transferred assets to below their book value; in the result, ratepayers would not be held harmless by the transfer.

3.6.3 Based on the Board's findings above, the transition costs associated with both the wind-down of the rental program and the reduction in employee positions will be subject to further uncertainty. Until such time as the Company takes action with respect to the alternatives available to it, the Board sees no need for the requested deferral account.

3.7 THE UNBUNDLED BUDGET

3.7.1 The Unbundled Budget presented by the Company was proposed as a basis for the Performance Based Regulation plan that is before the Board in E.B.R.O. 497-01. The Board is prepared to accept the adjustments to the cost of service identified for programs to be transferred to Consumersfirst at the end of this fiscal year, subject to the Company providing the actual amounts for ratemaking purposes. Depending upon the choice(s) the Company makes in response to the Board's findings in the present application, a different Unbundled Budget will result. Other aspects of the base budget for any PBR plan which the Board may approve will be dealt with in the E.B.R.O. 497-01 Decision.

3.7.2 The Board could not determine the extent to which the stranded assets identified by the Company are associated with the proposed treatment of the rental program. To the extent that any such costs are associated with businesses transferred out, they should not be reflected in the cost of service going forward.

3.8 ENERGY USE AND DEMAND-SIDE MANAGEMENT

3.8.1 As noted above, this issue was completely settled in the Settlement Conference. The Settlement Agreement set out certain commitments by the Company to address energy conservation and demand-side management concerns upon approval of its Application. It is the Board's expectation that any proposal brought forward by the Company in response to this Decision will take into account the terms of that Agreement.

4. COST AWARDS

4.1 COST AWARDS

4.1.1 The following parties applied for an award of costs: AMEC, CAC, CEED, Energy Probe, HVAC, IGUA, OAPPA, OCAP, Pollution Probe and the Schools.

4.1.2 In order to expedite the issuance of this Decision, the Board will address cost claims in a supplementary decision which will be issued in due course.

DATED AT Toronto March 31, 1999.

H. G. Morrison
Presiding Member

P. Vlahos
Member

A Portion of E.B.O. 179-14 and 179-15 Settlement Agreement from Exhibit B, Section 8.0 Pages 8 and 9 dated December 1, 1998.

D.3 Impact on Energy Use and Utility DSM Programs (Complete Settlement)

The following parties participated in the discussion of this issue: the Company, AMEC, CAESCO, CAC, CEED, Energy Probe, GEC, HVAC, IGUA, Schools, OCAP, and Pollution Probe.

There is an agreement to settle this issue on the following basis:

- The Company recognizes that its restructuring proposals in the EBO 179-14/15 application will have an impact on the way in which it designs and delivers DSM programs, particularly in the residential sector. Since the inception of DSM in 1995, many of the residential programs and a significant portion of the total results have been associated with the Rental Program.

- In its EBO 177-17 Decision with Reasons, the Board noted its concern that if the cost effectiveness of DSM programs is not maintained, ratepayers will be detrimentally affected. The Company will monitor the impact of completing its restructuring proposals and, as required, take appropriate steps to mitigate any detrimental effects.

- The Company will expand its program approaches and its delivery channels, in a restructured environment, to included a wider array of industry and trade allies. The Company will also broaden its monitoring and evaluation processes in order to track the impact of its programs on a broader market basis. In addition, the Company will file a comprehensive monitoring and evaluation plan with each DSM Plan, which will be developed with input from the DSM consultative process.

- The Company will also take an active role in advocating an increase, to or beyond the level that the Company has achieved in its Rental Program in recent years, in the Ontario Government's minimum standard for the efficiency of gas-fired water heaters.

The following parties agree with the settlement: the Company, AMEC, CAESCO, CAC, Energy Probe, GEC, IGUA, Schools, OCAP and Pollution Probe.

The following parties take no position on the issue: CEED and HVAC.

TAB 11

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2006-0021

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

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

EXECUTIVE SUMMARY

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, Union Gas Limited ("Union") and Enbridge Gas Distribution Inc, ("EGD") have been filing DSM plans in response to the directives of the Board in the EBO 169-III Report.

In the Board's EB-2005-0001 decision dealing with EGD's 2006 rates, the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities – this decision. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act. The Board's findings in this decision, therefore, are orders of the Board pursuant to section 36 of the Act.

At the beginning of the oral hearing the Board was presented several documents which segmented the issues list into four categories. The categories consisted of a list of completely settled issues, a list of partially settled issues to which most intervenors and the utilities agreed, a list of partially settled issues to which all intervenors agreed with the exception of the utilities, and, a list of completely unsettled issues. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The Board's decision deals with a large number of issues relating to DSM. Generally, a rules-based and framework approach has been established where appropriate and practical. Below is a list of the broader matters that have been decided.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and utility incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of the gas utilities in electric Conservation and Demand Management activities and initiatives

The Board will issue a Procedural Order to commence the next phase dealing with the determination of the input assumptions after which the gas utilities can file their respective three-year DSM plans.

DECISION –PHASE 1

CHAPTER 1 - INTRODUCTION

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, the gas utilities have filed DSM plans in response to the directives of the Board in the EBO 169-III Report.

The EBO 169-III Report provided guidelines to assist the utilities in the development and implementation of their respective DSM plans. Although the objectives and principles have evolved somewhat over the years to reflect changing market and industry conditions, they remain essentially unchanged. These DSM plans formed part of the gas utilities rate cases and were reviewed annually.

Over the past decade there have been occasions where rules for DSM programs have been challenged, requiring further interpretation and scrutiny by the Board. In addition, the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities, Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD"), in separate proceedings. This has lead to increased regulatory burden for all parties and inconsistent practices by the two utilities. These concerns and the heightened focus on conservation and demand side management for the energy sector as a whole were the impetus for the Board to re-examine the DSM regime as it pertains to these two gas utilities through this generic proceeding.

In the Board's partial decision in EGD's 2006 rates application (EB-2005-0001 / EB-2005-0437), the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act, 1998 (the "Act"). The Board's findings in this decision, therefore, should be considered orders pursuant to section 36 of the Act.

The Notice further stated that the following would be among the topics the Board would evaluate in making orders relating to the operation, evaluation and auditing DSM plans starting January 1, 2007:

- timing of the schedule for submitting and reviewing DSM plans,
- determination and use of planning assumptions for generic energy efficiency measures and custom projects,
- DSM budget as a percentage of utility annual revenue,
- structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities,
- structure and use of LRAM, SSM and DSMVA,
- process and content of program evaluations including the requirement for a third party audit process,
- length of plan, as well as updating the plan and reporting requirements,
- rules respecting free riders and attribution of energy savings, and
- the appropriateness of directing specific DSM measures to low-income consumers.

Other areas of focus will include the requirement for and role of the Consultative committee, filing requirements for the DSM plans and reporting requirements.

As the content of the topic list indicates, the intent of the proceeding was to streamline processes, harmonize practices where appropriate and re-examine the rules of DSM that had developed to date.

It was not the intent to revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169 III regarding the appropriateness of Demand Side Management being utilized by the Utilities in Integrated Resource Planning (IRP).

In the course of the proceeding, the Board received three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between EGD and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this “financial package” was considered by the parties to be un-severable. That is to say that the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors but not the utilities.

The Board held an oral hearing that commenced on July 10, 2006. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The non-utility parties to the hearing were Canadian Manufacturers & Exporters (“CME”), Consumers Council of Canada (“CCC”), Energy Probe, Green Energy Coalition (“GEC”), Industrial Gas Users Association (“IGUA”), London Property Management Association (“LPMA”), Low Income Energy Network (“LIEN”), Pollution Probe, School Energy Coalition (“SEC”) and Vulnerable Energy Consumer’s Coalition (“VECC”).

The full record of the proceeding is available at the Board’s offices. The Board has considered the full record but has summarized it in this decision to the extent necessary to provide context for its findings.

Chapter 2 deals with details of the completely settled issues. Chapter 3 addresses the issues contained in the “financial package”. Chapter 4 deals with the remaining issues. Chapter 5 deals with the issues respecting a common set of input assumptions, a common guide and with next steps. In that regard, this decision document is referred to as Phase 1. Appendix 1 contains details regarding some of the procedural aspects of the proceeding, including a list of parties’ representatives and witnesses.

CHAPTER 2 - THE SETTLEMENT PROPOSAL

A Settlement Proposal was filed with the Board on July 8, 2006 and was updated on July 11, 2006. The Board heard submissions from the parties and accepted the Settlement Proposal on July 11, 2006.

The Board acknowledges the effort of the participating parties to the Settlement Proposal and is pleased with the significant number of issues that were settled prior to the oral hearing.

Below are the completely settled issues which were accepted by the Board. To provide context to the balance of this decision, the Board sets out below the agreed upon phrasing of the settled issues. The numbering in brackets reflects the numbering that appeared on the Board's approved issues list for the proceeding.

Is a three year plan an appropriate term of a DSM plan? (Issue 1.2)

> "Parties agree that 3 years is an appropriate term for a multi-year DSM plan. Parties agree that the issue of whether and, if so, how a multi-year DSM plan should be aligned with a Utility's Incentive Regulation ("IR") period should be determined by the Board in the context of establishing the IR mechanism and rules, and cannot be determined in this proceeding in the absence of information on the structure and term of the IR regime adopted by the Board."

How are DSM parameters adjusted inside a multi-year rate making process? (Issue 1.6)

Parties referred this issue to completely settled Issue 1.2.

Should budgets, programs, targets, incentives and other plan components be established on an annual or multi-year basis? (Issue 1.8)

> "The approval of multi-year DSM plans will provide the utilities with the certainty of funding for programs which will have forecast life spans of more than one year. DSM plan components will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-plan plan.
>
> As this settlement provides that the budget, SSM mechanism, LRAM, and DSMVA are all developed and measured on an annual basis within a multi-year plan, it is appropriate that amounts be recorded in all DSM variance or deferral accounts on an annual basis (market transformation amounts may be an exception)."

How should the budget be allocated between customer classes in rates? (Issue 1.9)

> "Cost allocation in rates shall be on the same basis as budgeted DSM spending by customer class. This allocation should apply to both direct and indirect DSM program costs."

Should the TRC [Total Resource Cost] test be the only test used to screen measures and/or programs for DSM plans? If no, what other tests should be used and how should these be applied? (Issue 2.1)

> "TRC shall be the only formal screen to determine whether a measure or program can be considered for inclusion in the portfolio. EBO 169-III identified numerous other considerations and tests that could be used to determine which measures and programs are actually selected for the portfolio in any given year, and those considerations and tests should continue to apply."

How should free rider and savings input assumptions be determined? (Issue 3.1)

> "Parties agree that input assumptions such as free rider rates, prescriptive measure savings assumptions, incremental equipment costs, measure lives and avoided costs (natural gas, electricity and water) shall be based on research utilizing the best available data at the time a multi-year plan or new program or significant new program design is developed. These assumptions shall be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated on a regular basis during the plan period as part of each Utility's ongoing evaluation and audit processes."

What certainty is required that the assumptions are set for the duration of the DSM plan? (Issue 3.3)

> "The time at which changes in assumptions become effective shall differ depending on the use to which the assumption is being put:
>
> ***Program Design and Implementation.*** The Utilities agree to the principle that their DSM programs should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.
>
> ***LRAM.*** Assumptions used will be best available at the time of an audit. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

SSM. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."

What is the mechanism to determine if an input assumption needs to be reviewed or researched? (Issue 3.4)

"The Utility may of its own initiative or at the request of the Evaluation and Audit Committee ("EAC") commence a review of or research into assumptions."

How should the (LRAM) mechanism be structured? (Issue 4.2)

"The parties agree that the LRAM mechanism shall be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report results.

For Union, the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

For EGD, the first year impact will be calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

Both of these processes for the Utilities reflect the status quo.

The LRAM account shall be cleared annually.

For purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and shall apply from the beginning of the year being audited. See also Issue 3.3."

What evidence should be submitted to demonstrate that all conditions for clearance have been met? (Issue 4.3)

"Parties agree that the Utilities shall file an Audit report and any other backup needed to support the volumes used in the LRAM calculation. The Audit report will be prepared by an independent auditor to ensure accordance with Board approved rules. The auditor shall provide an opinion on the LRAM proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in Issue 9.3."

Is a third party audit required to verify LRAM calculation prior to clearance? (Issue 4.4)

"Yes, see issue 4.3 above."

How should LRAM costs be allocated between customer classes? (Issue 4.5)

"The LRAM shall be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class."

Should an incentive mechanism be in place? If yes, (Issue 5.1)

"Yes."

Is a third party audit required to verify year-end SSM calculation? And if required, what should be the audit principles, scope and timeline? (Issue 5.3)

"Parties agree that an independent auditor shall complete an evaluation audit with the purpose of verifying the claimed financial results and that the DSM shareholder incentive amounts (being the SSM and the incentive available in respect of market transformation programs) are calculated in accordance with the Board approved methodology. The audit shall provide an opinion on the DSM shareholder incentive amounts proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in issue 9.3."

How should SSM costs be allocated between customer classes? (Issue 5.4)

"Parties agree that DSM shareholder incentive amounts shall be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes."

What evidence is required to clear the DSMVA? (Issue 6.4)

"The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis."

How should DSMVA balances be allocated between customer classes? (Issue 6.5)

"The Utilities shall allocate the DSMVA amounts in rates based on the Utility's DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class shall be allocated to that customer class for rate recovery purposes."

Should the DSM consultative be continued? If yes, (Issue 7.1)

"When required or useful, the utility will engage and seek advice from a variety of stakeholders and experts in the development and operation of its DSM program. As the utility is ultimately responsible and accountable for its actions, consultative activities shall be undertaken at its discretion. However, at a minimum, each utility will hold two consultative meetings annually. The purpose of the meetings will be to:

- Review annual results (the Evaluation Report will be sent to the Consultative annually for review) and select the Evaluation and Audit Committee ("EAC"). Three members will be selected using the current process used to select the Audit Sub-Committee; the fourth member will be the utility. In the current process, the members of the Consultative nominate individuals to stand on the committee. Then each member of the Consultative votes for the three members they would like on the committee. The three with the highest number of votes form the committee.

- Review the completed evaluation results.

The Utilities each acknowledge the principle that stakeholder consultation has proved valuable. They each intend to continue to take advantage of the input of the consultative as long as the consultative is adding value and the overall cost of the process is reasonable."

What role should the Consultative have in the DSM planning, design, approval and audit process? (Issue 7.2)

Settlement on this issue was referred to completely settled Issue 7.1.

How often should the Consultative and LDCs meet? (Issue 7.3)

> "A utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement, subject to the requirement to meet twice annually set out under Issue 7.1 above. See Issue 7.5."

What is the appropriate amount that should be budgeted for Consultative and Sub-committee expenses? (Issue 7.4)

> "The utility shall determine as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs."

How should participation in the Consultative committee be determined? (Issue 7.5)

> "The utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement. All intervenors in the Utility's most recent rate case shall be entitled to participate in the consultative meetings described in issue 7.1 above."

Should a percentage of the DSM budget be allocated to research? If yes, (Issue 8.1)

> "Parties agree that the Utilities should conduct forward-looking DSM research. The appropriate level of budgets for research shall be determined by each Utility from time to time (depending upon need, market conditions, etc.) and each Utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board."

How should it be determined that research is required and when? (Issue 8.2)

> "The utility shall determine the research needed to inform program assessment as part of its ongoing operational responsibilities and to ensure the long term viability of its DSM program. In making this

determination, the Utility shall give due consideration to any recommendations of the EAC, the Auditor, and the consultative."

To reduce duplication, should certain research commitments be combined for both LDCs? (Issue 8.3)

"Each Utility shall be responsible and accountable for its research activities and expenses. The utility is expected to seek and leverage efforts with third parties where appropriate but it is recognized that unique circumstances and objectives may exist that preclude partnering in some instances."

How often should a DSM market potential study be conducted by the LDCs? (Issue 8.4)

"Market potential studies, or updates to an existing study, must be filed by each Utility together with its multi-year plan. The Utility may, in its discretion, do additional studies of market potential or updates during its plan."

What is the purpose of evaluation reports and what should they contain? (Issue 9.1)

"EGD and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of results. In order to inform stakeholders on the activities and results of the DSM programs undertaken, the utility shall file annually, a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and the evaluations conducted in support of those numbers.

It is the purpose of the evaluation and audit process to review all input assumptions related to the delivery of DSM over the period of the multi-year plan. To assist with that purpose, the parties propose the establishment of an EAC to engage stakeholders in the development of an evaluation plan and budget and to engage stakeholders in a review of the evaluation results as they become available over the term of the plan."

Is a third party audit of the evaluation report required? And if required, what should be the audit principles, scope and timeline? (Issue 9.3)

"The parties agree that a third party audit of the Evaluation Report is required. The auditor will be retained by the utility who determines the scope of the audit. It will be the role of the auditor to:

- Provide an opinion on the DSMVA, SSM and LRAM amounts proposed and any amendment thereto
- Verify the financial results in the Evaluation Report to the extent necessary to give that opinion
- Review the reasonableness of any input assumptions material to the provision of that opinion
- Recommend any forward looking evaluation work to be considered

The auditor shall be expected to take such actions by way of investigation, verification or otherwise as are necessary for the auditor to form their opinion. The auditor, although hired by the utility, must be independent and must ultimately serve to protect the interests of stakeholders."

Should there be an Audit Sub-committee with intervenor participation? And if yes, what role should the Audit Sub-committee have? (Issue 9.4)

"As described in Issue 9.3 above, parties agree that there should be an audit subcommittee entitled EAC. Participation in the EAC will be determined as set out in Issue 7.1.

The EAC will provide formal input into the evaluation plan. In regards to evaluation activities the EAC will continue to have an advisory role in the following:

- Consultation prior to the filing of the DSM plan on evaluation priorities for the next three years (or the duration of the multi-year plan). The utilities will, as part of their implementation plan, review all of the input assumptions over the course of each multi-year plan.
- Review and comment on evaluation study designs. Input on the research methodology used to determine the input assumptions.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the multi-year plan.
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC will ensure that all comments on the Evaluation Report from the Consultative are reviewed by the auditor.
- Following the audit, review of the Evaluation Plan annually to confirm scope and priority of identified evaluation projects.
- The EAC will be responsible for meeting the reporting guidelines of the Board (found at Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities). The EAC will provide a final report within 10 weeks from the later of, the receipt of the Evaluation Report and supporting evaluation studies from the Utility, or the hiring of the auditor. Recommendations of the EAC with respect to DSMVA, LRAM and SSM clearances shall be included in the EAC's final report. The EAC shall not consider any further information subsequent to the Board's filing deadline each year."

What characteristics are required to determine that a program is either a market transformation or lost opportunity program? (Issue 10.1)

"Market Transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not

> necessarily measured by number of participants and (c) have a long term horizon.
>
> Lost Opportunity programs are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement, in a subsequent planning period."

How should it be determined that utility has achieved any prescribed target? (Issue 10.3)

and

What should be the length of a market transformation and lost opportunity program? (Issue 10.5)

and

What is the appropriate level of funding for a market transformation or lost opportunity program? (Issue 10.6)

Settlement on these issues was referred to completely settled Issue 10.7.

How should a program incorporate the following elements; information and education activities; incentives; research; activities to reduce market barriers such as building codes and energy efficiency appliance standards; and coordination with other entities (e.g. OPA)? (Issue 10.7)

> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

Is it appropriate to use DSM funds for fuel switching to natural gas? (Issue 14.1)

> "Fuel switching is an important activity that can help alleviate some of the electricity supply programs faced by the province; however, the utility shall not use DSM funding to promote fuel switching to natural gas. The utility will pursue fuel switching activities as part of its marketing efforts that will be included in its rate case or other suitable application."

Is it appropriate to use DSM funds for fuel switching away from natural gas? (Issue 14.2)

> "Where fuel switching away from natural gas aligns with the Utility's DSM objectives the Utility may pursue these activities."

CHAPTER 3- PARTIAL SETTLEMENT (FINANCIAL PACKAGE)

In addition to the completely settled issues, the Board was presented with a list of partially settled issues. Union, EGD, CCC, SEC, Energy Probe, IGUA, LPMA, and VECC (the "Partial Settlement Proponents") were parties to a complete agreement on a number of issues. Certain of these issues were presented as a package (the "Financial Package") which the parties presented as being un-severable; i.e. if the Board did not accept the entire package, the Financial Package agreement would be withdrawn. The Financial Package dealt with:

- DSM budgets (Issue 1.3),
- DSM plan targets (Issue 1.4),
- allocation of DSM budgets amongst customer classes (Issue 1.7),
- the DSM incentive mechanism (Issue 5.2),
- the DSM variance account (Issues 6.1, 6.2, 6.3),
- market transformation and lost opportunity program budgets and utility incentives related to them (Issues 10.2, 10.4, 10.8), and
- targeted programs for low income customers (Issues 13.1, 13.2, 13.3).

The Partial Settlement Proponents explained that the individual elements of the Financial Package were tied together, and that to change one element would have repercussions on other elements. On the opening day of the hearing, the Board explained to the parties that it would hear whatever evidence the parties chose to lead; however, if at the conclusion of the hearing the Board determined that it did not wish to accept the Financial Package in its entirety, it would not re-open the hearing to hear fresh evidence on any of the issues. The Partial Settlement Proponents subsequently informed the Board that they would continue to exclusively support the Financial Package, and would not present any evidence to be considered in the event that the Board did not accept the entire Financial Package.

In addition to the Financial Package, the Partial Settlement Proponents reached a partial settlement on a number of other issues that could be considered individually. This chapter deals only with the Financial Package; the remaining partially settled issues will be addressed in Chapter 4.

The chief proponents of the Financial Package in the hearing were the utilities through their witness panels. The other Partial Settlement Proponents did not present witnesses in support of the Financial Package, but did conduct what was described as “friendly” examinations of the utility witnesses on these issues. The parties opposed to the Financial Package cross-examined the utility witnesses and, in some cases, filed their own proposals.

The Board will accept the Financial Package as presented by the Partial Settlement Proponents. As the Board explained when considering the meaning of a partial settlement on July 10, the Board has considered all of the issues in the Financial Package on an issue by issue basis. Taken individually and as a whole, the Board finds all of the proposals contained in the Financial Package to be reasonable.

The Board is pleased that the Financial Package amounts to what is largely a “rules-based” approach. Many of the major elements of the three year DSM plans will essentially be locked in for the term of the plan, and will not require further review by the Board during this period. This should result in significant regulatory savings for the parties, the Board, and, ultimately, for ratepayers.

The Board finds that the Financial Package strikes an appropriate balance between advancing DSM forward through higher budgets and ultimately higher TRC savings targets, while not forcing the utilities to try to spend money that they indicated they would have trouble spending in a cost effective manner. The Board is also satisfied that the Financial Package will not cause undue rate impacts to ratepayers given the relatively modest nature of the proposals, in light of the overall revenue requirement of the respective utilities.

In addition to the overall comments above, the Board has the following remarks on the individual issues that comprise the Financial Package.

How should the financial budget be determined? (Issue 1.3)

The Partial Settlement makes the following proposal.

> "Parties in agreement with this partial settlement accept that a DSM budget cap should be developed using the following formulaic approach in each year of a multi-year DSM plan. For the first year, the budget for EGD will be $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget will be $17.0 million an increase of $3.1 million or approximately 22% from its 2006 budget.
>
> In the second and subsequent years of a multi-year DSM plan, the DSM budget for each year of the plan will be determined by applying an escalation factor of 5.0% for EGD and 10% for Union to the budget developed for the immediately preceding year. The purpose of the application of different escalation factors for EGD and Union is to address the desire by some parties that the difference between the level of spending by EGD and Union be narrowed. The parties agree that this formula results in budgets of $23.1 million and $24.3 million for EGD in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.
>
> Parties to this partial settlement agree that the Utilities remain obligated to develop, and spend monies on, cost-effective DSM programs up to the budget amount developed by this methodology."

The Board is satisfied that the Financial Package proposal reaches an appropriate balance between increasing DSM budgets and approving budgets which can be spent in a cost effective manner. Both Pollution Probe and GEC argued in favour of much higher budgets; however, the Board is not convinced that the utilities could currently spend these amounts cost-effectively.

Should there be plan targets and if so, should they be volumetric or based on TRC values? (Issue 1.4)

The Financial Package agreement makes the following proposal:

> "Parties to this partial settlement further agree that there will be an annual TRC target. The parties agree to phase in a formula over the next three years which will set this target, as described below, by averaging the Utility's actual audited TRC results over the previous three years and applying to this figure an escalation factor equal to 1.5 times the amount by which the utility's budget is increased. The parties agree to phase in the aforementioned formula over the next three years beginning with an agreed upon target for each utility in 2007 which, for Union will be $188 million and for EGD $150 million.
>
> Furthermore, the parties agree that, in the event the avoided costs used by the utility are, at a later date, updated, the actual audited results from previous years used to calculate the target will be adjusted to reflect these updated avoided costs.
>
> Finally, and for greater certainty (and as an example), set out below is the formula by which the target will be set for Union, with 2010 provided for illustrative purposes only:
>
> • 2007 - $188 million.
>
> • 2008 - The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2009 - The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

For EGD, the formula by which the target will be set is as follows, with 2010 provided for illustrative purposes only:

• 2007 - $150 million

• 2008 - The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

• 2009 - The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

•2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie.7.5%).

The “actual audited TRC values” shall be the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for LRAM purposes. By way of example, if a free rider rate is increased in the 2009 audit carried out in the first half of 2010, under the partial settlement that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in free rider rate identified in the audit.”

The Board is satisfied that the Financial Package proposal sets reasonable TRC targets for the utilities. The Board notes that the formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board finds this formula to be preferable to setting the targets for all three years in advance.

The Board notes that the target for Union in year one of the plan will actually be lower than its Board approved target for 2006. The Board heard evidence from Union that the TRC target for 2006 had been set at a level that it will not attain. Union indicated that according to its current projections for 2006, the company will likely achieve TRC savings in the range of $170 million (on a target of $216 million). The Board accepts Union's evidence in this regard, and finds that a target of $188 million in year one of the three-year plan is reasonable.

On what basis should the DSM program spending be targeted amongst customer classes? (Issue 1.7)

The Financial Package agreement makes the following proposal:

> "Parties acknowledge that EGD's and Union's rate classes and customer needs are not identical, and hence it is not appropriate to restrict spending based on a rigid formulaic approach by rate class. The Utilities acknowledge and accept the principle that their portfolio of DSM programs should provide customers in all rate classes and sectors with equitable access to DSM program(s) to the extent reasonable, and that this principle must be balanced and consistent with the principle of optimizing cost-effective DSM opportunities. To the extent that a proposed multi-year plan proposes DSM sector (ie. residential, commercial, or industrial) level spending that is significantly different than the historical percentage levels of spending in those sectors, the utility will provide its explanation for this in its proposed multi-year plan. Parties may challenge any such

explanation, or its impacts. The Board will then determine whether to approve the revised spending ratios, and if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate. (Issue 1.7)"

The Board is cognisant of the tension between ensuring that each rate class is allocated an appropriate portion of DSM funds on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they fall in on the other. The Board is satisfied that the Financial Package proposal finds the appropriate balance.

What is an appropriate incentive mechanism and how should it be calculated? (Issue 5.2)

The Financial Package agreement makes the following proposal:

"The parties to this agreement agree that an SSM shall be established for the first year of the plan and shall be in effect for each year of each multi-year plan.

Parties agree that the amount of any SSM shall not be included in the Utility's return on equity ("ROE") for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The parties agree that for the purposes of this settlement, the TRC indexing target for 2007 for EGD will be $150 million, and for Union, $188 million. Targets for subsequent years shall be set in accordance with the formula in Issue 1.4. The cumulative SSM incentive payment to each utility for achieving their respective TRC target will be set by a formula, and at 100% of TRC target will be $4.75 million. For the purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM will not be changed retroactively. For clarity, changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, input assumptions for purposes of the SSM remain fixed for 2007, and any changes to input assumptions which change as a result of the audit of the 2007 results which is undertaken in early/mid-2008 will apply from the beginning of the 2008 year forward. Also see Issue 3.3.

For both Utilities, the following formula applies for the determination of the SSM curve and resulting cumulative payout. The SSM payout will be calculated based on the results as they apply along the curve and each of the following percentage thresholds do not represent lump sum payments for reaching the threshold but simply serve to structure the SSM curve based on targets and SSM amounts as agreed to by the supporting parties:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000.

The parties agree that the annual 'cap' of $8.5 million will increase annually by the Ontario CPI as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI as determined at October of 2007).

See also issue 10.4 for the incentive available to the utilities in respect of market transformation programs"

During the hearing, the utilities provided the formula in calculating SSM, which is reproduced below:

> "For achievement of between 0 and up to 25.0% of the annual target, the SSM payout shall equal $900 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 25.0% up to 50% of the annual target, the SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 50.0% up to 75.0% of the annual target, the SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1% of target achieved above 50.0%, and
>
> For achievement of greater than 75.0% of the annual target, the SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1% of target achieved above 75.0% to a maximum of the SSM annual cap."

There was a complete settlement on issue 5.1, in which all parties agreed that there should be an incentive mechanism. The Financial Package proposal for issue 5.2 presents a formula for determining the exact amount of the SSM payout based on the level of success each utility has achieved in hitting its TRC targets. The Financial Package proposal calls for an escalating incentive scale which starts at the first dollar of TRC net benefits achieved. This proposal marks a change from the current Board approved practice where the utilities are required to reach a certain level of net TRC savings before any incentive is realized. The Board is satisfied that this change to the *status quo* is appropriate. The Board is persuaded by the utilities' evidence that the proposed structure is more likely to attract management attention to DSM programs. The Board is also comforted by the fact that the incentive payments for performance below 50% of the TRC target is very low. Further, the $8.5 million cap on incentive payments for any one year ensures that ratepayers will not have to pay an undue amount if a utility achieves extraordinary success.

Demand Side Management Variance Account (Issues 6.1, 6.2, 6.3)

The Financial Package agreement makes the following proposals:

> “Parties agree that the DSMVA shall be continued. The DSMVA shall be used to “true-up” the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. ”
>
> “There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility’s DSM budget for that year. ”

The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers.

Market Transformation (Issues 10.2, 10.4, 10.8)

The Financial Package agreement makes the following proposals:

> "Every utility DSM plan should include an emphasis on lost opportunity and market transformation programs and activities. For purposes of this agreement, parties agree that this emphasis will consist of a market transformation budget of $1.0 million per utility per year and is included in the total budget amounts referenced in issue 1.3."
>
> "Parties agree that each utility is entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The measurement and calculation methodologies to determine whether this amount has been earned in the year shall be detailed by each utility in its multi-year DSM plan. For clarity, this amount is in addition to any amount earned at issue 5.2. By way of example, a Utility may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan is approved by the Board including that program, the Utility will be entitled to a $250,000 incentive in each year that it meets the stated market share goal."
>
> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> "Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

CHAPTER 4 - REMAINING NON-SETTLED ISSUES

The previous chapter, Chapter 3, dealt with the settled issues and the partially settled issues that were presented to the Board as a “financial package”. The following chapter, Chapter 5, includes discussion of Issue 3.2 relating to the question of whether there should be a common guide. This chapter, Chapter 4, deals with the remaining non-settled issues that were addressed during the oral hearing.

What should be the timing of the schedule for submitting and reviewing Demand Side Management (“DSM”) plans? (Issue 1.1)

The Board was presented with a partial settlement. All intervenors agreed as follows:

> “…DSM plans should be filed at least nine months prior to the plan period to which they relate, to give sufficient time for stakeholders and the Board to consider them, and for Board approval prior to the plan period commencing.”

The utilities believe that filing the DSM plans four months in advance of the initial plan year will allow sufficient time to have the plan in place by the beginning of the following year. The utilities indicated that this would allow them to file final results from the previous year’s audit, rather than interim un-audited results.

For clarity, the timing issue here relates to future DSM plans. The timing of filing for the inaugural three-year plan is dealt with elsewhere in this decision.

The Board notes that a filing date at least nine months in advance would entail the presentation of un-audited performance of the plan’s second year. This may likely involve updates once the results are audited. The Board is of the view that updates should be avoided where possible, as they are generally not conducive to an efficient review. While the Board anticipates that a four month time frame will likely be adequate to accomplish the review given the rules approach adopted by the Board, there is the possibility that it will not. In that case, the consequence is a start date that may not immediately follow the last day of the previous term of the plan. While this may not be desirable, it would be of little adverse consequence as the previous plan would continue. It is in the Board's view a reasonable risk to take in order to obtain the benefits of an efficient review. The Board therefore accepts the utilities' proposals that subsequent plans be filed four months in advance of their commencement.

What process and rules should be available to amend the DSM plan? (Issue 1.5)

There was no settlement (complete or partial) on this issue.

In a response to an undertaking (J2.2), the utilities referenced the preamble of the Partial Settlement which reads

> "For greater clarity, where any settled issue is expressed to continue throughout a multi-year plan, no party to that settlement may seek to re-open that issue with respect to either Utility in any other proceeding prior to the earlier of a) the Board's consideration of the multi-year plan of that Utility, or b) a further hearing on DSM in which the Board has determined that such issue is to be considered "

and stated that

> "… it is the position of the utilities that the Board should amend a multi-year plan during the currency of that plan only in exceptional circumstances. It is expected that with the proposed language, all stakeholders will recognize that any application for an amendment must meet a very high onus to demonstrate undue harm. The intent of the above section is not to provide parties with an opportunity to reopen the framework rules established in this proceeding."

As noted at the oral hearing, no rule can prevent requests for review, or should for that matter. It would not be in the public interest to disallow re-opening of the plan in midstream under any circumstances. At the same time, the purpose of this generic initiative is to avoid unnecessary re-visitation of DSM issues.

Demonstration of "undue harm" was accepted as a reasonable principle by intervenors. The Board concurs that it is a workable principle and useful in the circumstances. There was also support for the proposal by SEC that any party claiming undue harm must first seek leave of the Board before the matter is thoroughly reviewed, and leave should be given only in exceptional circumstances. The Board notes that if a proposed amendment came forward either by way of a motion or by way of application, the Board has the authority and tools to subject the request to the appropriate scrutiny, and to ensure that the intentions of the parties and the Board are respected.

As for the proposal by the utilities that the Board use its cost assessment powers as a further measure to dissuade frivolous requests, this option is always available to the Board and can be used when warranted. This applies equally to intervenors and the utilities.

Should a TRC threshold be established to determine if a measure and/or program is cost effective or should it be based on the cost effectiveness of the portfolio? If so, what should the value be? (Issue 2.2)

The Board was presented with a partial settlement. All parties except SEC agreed as follows:

"The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs)."

SEC argued for a screen value of 1.2 rather than 1.0 on the basis that TRC is based on assumptions that change, so it would be appropriate to build in a margin to ensure feasibility. SEC noted that nothing is lost since it appears that there is much more DSM available than the utilities can handle and thus, instituting a higher threshold programs would be better. SEC noted that the exception related to the screen value for pilot programs would still exist.

In the Board's view, the availability of DSM initiatives that exceed the 1.0 cost-benefit ratio is not a compelling argument for deviating from a widely-practiced threshold of 1.0. A program that yields a benefit cost ratio over 1.0 does provide positive net benefits and it would not be appropriate to knowingly forego such benefits. As for SEC's argument that a higher threshold would avoid the risk of uneconomic programs, this can be addressed by instituting more robust input assumptions. Moreover, the risk of uneconomic programs is offset by the fact that, from a societal perspective, the TRC test does not reflect the positive aspects of mitigating negative externalities that are inherent in gas consuming activities. In fact the risk of undertaking uneconomic programs is self-correcting by the incentive by the utilities to maximize rewards by maximizing TRC benefits. For the above reasons, the Board does not accept SEC's suggestion.

However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.

How often should avoided gas costs be calculated and should the Local Distribution Companies ("LDCs") use identical avoided costs? (Issue 3.5)

There was no settlement (complete or partial) on this issue.

EGD undertook to explore if the utilities could produce a common set of avoided costs and responded (J2.4) as follows:

> "Each Utility will calculate avoided costs for natural gas, electricity and water that reflect the cost structure and service territory of the Utility. In order to ensure consistency, a common methodology will be used to determine the costs. The Utilities will coordinate the timing for selecting commodity costs so that they are comparable.
>
> The avoided costs will be submitted for review as part of the multi-year plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs will be updated annually.
>
> As avoided costs are long term projections, updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs will be used to calculate both the target (relative to 2007) and incentive amount, therefore it is anticipated that the relative impact would be minimal."

Only GEC argued against the utilities' proposal. It argued that the utilities should use common values for gas commodity, electricity and water. With respect to the avoided distribution system costs (e.g. pipes and storage etc.) which may vary by utility, GEC submitted that the utilities should be required to demonstrate how different these values are so that the Board can determine whether or not the difference is material.

The Board does not accept GEC's proposals. Avoided gas costs are a significant component of calculating TRC benefits. Gas costs can be different for each utility depending on, among other things, its gas supply management policies and practices.

With respect to system costs, these are certainly unique to each utility and they too are an important part of the TRC benefit calculation. The benefits of estimating and measuring with more precision the TRC values for DSM programs outweigh, in the Board's view, the costs of the incremental effort to determine and review the different values for gas commodity and system costs.

The Board also notes that the methodology for estimating the values for natural gas commodity, system costs, electricity and water will be common for the two utilities, which will ensure some measure of consistency and efficiency.

The Board accepts the utilities' proposals.

Should the LDCs be entitled to revenue protection? (Issue 4.1)

The Board was presented with a partial settlement on this issue. All parties except CME agreed that the utilities should be entitled to revenue protection.

By accepting the "financial package" settled issues earlier in this decision, the Board has not found merit in CME's argument that the utilities should not be entitled to revenue protection. As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges), there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM.

What is the appropriate level of funds that should be budgeted for an evaluation report and audit? (Issue 9.2)

The Board was presented with a partial settlement on this issue. All parties except GEC agreed as follows:

"The Utilities shall ensure that DSM budgets and spending include adequate funding to complete the required annual evaluation and audit activities. The utility is responsible and accountable to ensure that evaluation and auditing activities are concluded in a timely fashion and that the associated costs are reasonable."

GEC argued that 3% of the DSM budget should be allocated to evaluation and audit over the three year period. GEC noted that the utility should have the flexibility to move spending between years to balance the lumpiness of spending. GEC noted that this budget should only be spent if required.

The Board fails to see the rationale or benefit of GEC's suggestion. In fact the Board only sees lost DSM program opportunities as the utilities will not be able to access any unspent portion of a fixed budget reserved for evaluation and audit. The Board does not accept GEC's proposal. The utilities should be spending in evaluation and audit as required and as prudent.

What attribution rules or principles should be applied to jointly delivered DSM programs? (Issue 11.1)

There was no settlement (complete or partial) on this issue.

The issue for the parties was how the framework rules will deal with situations where a utility operates or participates in a program with a non-rate-regulated third party and, where this occurs, how should the determination of the TRC benefits be made. For completeness, the Board also makes a finding on attribution between Board rate-regulated parties.

The utilities advocated the centrality principle, as decided by the Board in EGD's EB-2005-0001 rate case. Under the centrality principle, it would be considered that the utility played a central role if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. In such circumstances the utility would be entitled to 100% of the TRC benefits.

Where the utility's role is not considered central, the utilities differed. EGD advocated a scaled role approach, whereas Union proposed that the attribution of TRC benefits would be measured by free ridership. In Union's view, there is no material distinction in the two approaches as both would likely produce the same result. The utilities agreed that it should be the same arrangement for both as determined by the Board.

In the view of CCC and GEC, the rule of centrality is not particularly helpful at avoiding the need to analyze each project or proposal.

The Board notes that the utilities did not dispute the suggestion that attribution of benefits for jointly delivered DSM programs must be done on a case-by-case basis. The Board agrees that this is a reasonable approach. The issue is whether the centrality principle should be maintained.

The Board recognizes that it accepted the centrality principle in the EB-2005-0001 rate case when it dealt with EGD's EnerGuide for Houses program. What makes the re-assessment necessary is the fact that this is a generic hearing for the gas distributors and it is appropriate to review the rules *de novo*. In that regard, the Board notes that, pursuant to the settled and approved issues, there is now a delineated role for the evaluation and audit committee in respect of programs pursuant to the settlement agreement and the Board's acceptance of the agreement. Specifically, the attribution rules set by the Board will be used by the evaluation and audit committee to assess and settle the TRC savings attributable to the utility's role, which will ultimately be reviewed by the Board.

As the utilities concede, the centrality rule is not absolute. There can be considerable judgment in determining whether or not the role of the utility is central in a particular program. Attribution on the basis of the utility's participation that is considered incremental to the program on the other hand appears to remove some of the controversy, and it does not preclude full 100% attribution to the utility. However, a drawback is that the incrementality approach may not adequately and fairly capture situations where a program would not have existed at all if it were not for the utilities.

On balance, the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. The experience to be gained over the next three years will inform as to the suitability of continuing with this approach after that point.

This leaves the difference in approach by the two utilities where centrality is not claimed or demonstrated.

The Board accepts the utilities' position that the distinction between their approaches is without a difference. The utilities' differences reflect different internal practices, as noted by the utilities. The utilities acknowledge that either approach would involve the evaluation of attribution of each program by the evaluation and audit committee, and ultimately by the Board. However the utilities accept that there should only be one common approach, to be determined by the Board.

The Board prefers the free ridership approach advocated by Union as this would be more consistent with the general approach for measuring TRC benefits in other DSM activities implemented by the utilities.

The TRC benefits for program partnerships with Board rate-regulated entities (e.g. electricity distributors) shall be allocated in the manner indicated in the electric TRC Guide, as was canvassed at the oral hearing. That is, a gas distributor partnering with an electricity distributor shall claim all of the benefits associated with the gas savings.

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> “Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account”.

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

VECC submitted that although the fairest way to address attribution for custom projects would be on a project-by-project basis, a portfolio average approach can be acceptable for administrative efficiency, but with the conditions that there should be emphasis on sector-by-sector as suggested by LPMA.

The Board sees merit in the notion of differentiated free ridership rates by market segment, at least for large and small enterprises. However, this is a significant undertaking. The utilities revealed that at present there are over one thousand custom projects within EGD and a fifth of that within Union. A segmentation analysis would need to be done on a sample basis, statistically justified, and reviewed by the parties and the Board. Ordering such studies for the two utilities for this plan may jeopardize the timetable of filing and implementing the respective DSM plans. The Board also notes the testimony by Union's witness that any differences in free ridership rates through market segmentation may at the end balance out and in fact support a single rate.

For these reasons the Board accepts a portfolio average approach for custom projects. The free ridership rate for custom projects will be determined as part of the process that will determine the input assumptions.

For the next generation multi-year plans, the Board expects the utilities to propose common free ridership rates for custom projects that are differentiated appropriately by market segment and technologies.

Should custom projects have a third party or an internal audit and if so, what would be the audit scope and process of the audit? (Issue 12.2)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Custom projects should be audited using the same principles as any other programs. Audit activities should be sufficient for the auditor to form

an opinion on the overall SSM, LRAM and DSMVA amounts proposed in the Evaluation Report."

EGD proposed that the custom projects be audited as part of its portfolio results based on a significantly appropriate representative sample. The auditor would then confirm the results and these would be included for the purposes of calculating SSM and LRAM, consistent with the completely settled Issue 3.3.

Union proposed that, as custom projects form a large part of Union's DSM portfolio, they should be assessed by a third party, and noted that this is in fact Union's current practice. Union explained that a statistically significant sample of both the largest and smallest subset of projects should be evaluated by a third party evaluator, hired by the utility. The evaluator would not be the auditor because of the particular technical expertise required to review custom projects. The report of the technical expert would form part of the evaluation report, which would be forwarded to the auditor.

The Board notes that the distinction between the Union and EGD proposals is that, in Union's case, the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor. In EGD's case, that first cut is done in-house but EGD still engages a third party to do an evaluation of the sampling of its custom projects. Although in both cases the results would be forwarded to the auditor for review, the Board is of the view that a common approach should be adopted for the two utilities. The Board prefers Union's current practice where the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor.

Union proposed the adoption of the rule in the TRC handbook for electric CDM, where the projects selected for assessment should consist of a random selection of 10% of the large custom projects representing at least 10% of the total volume savings for all custom projects and consist of a minimum number of five projects. The Board adopts this proposal, which shall apply to both utilities.

[With respect to custom projects], how should savings be determined and what documentation is required? (Issue 12.3)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life, so for example should include a factor for the possibility that a measure will not be used for its entire engineering life (due to bankruptcy, change in operations, etc.)."

During the hearing, a complete settlement was considered to have been reached by all parties by truncating the text as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life."

The Board concurs with the settlement.

[With respect to custom projects], should the volumetric savings recorded be actual or forecasted volumes and what documentation is required to verify this result? (Issue 12.4)

In the Partial Settlement, parties referred this issue to Issue 12.3, which in turn was considered to have settled by the parties during the hearing.

The Board approves this settlement.

[With respect to custom projects], how will an appropriate base case be determined? (Issue 12.5)

The Board was presented with a partial settlement on this issue. All intervenors and Union agreed as follows:

> “Only the part of the project that the Utility influenced is to be counted for SSM or LRAM purposes.”

The Board notes that only EGD opted out on the basis that it does not know the implications of the word “influence”. The Board is not in a position to provide assistance to EGD in this regard as EGD itself was not clear as to the relief that it is seeking. However, the Board’s findings in this decision taken in their entirety should help alleviate EGD’s concerns. In particular, the Board does not see how the proposed wording would invalidate settled Issue 3.3, which is EGD’s stated concern.

The Board accepts the partial settlement on this issue.

How should the funding levels and targets, if any, for the gas utilities’ electricity to natural gas fuel switching programs be determined? (Issue 14.3)

The Board was presented with a partial settlement on this issue. All intervenors agreed as follows:

> “Programs promoting fuel switching to natural gas, which should be funded from the marketing budget of the Utility, should, just as with DSM programs, seek to balance maximization of TRC benefits with minimization of rate impacts.”

Union noted that that all parties agreed that fuel-switching to natural gas is not a DSM activity (and DSM funds should not be used for this purpose) and fuel-switching away from natural gas may be appropriate in certain circumstances and may therefore constitute DSM. Union stated that it is simply seeking guidance from the Board or approval to bring an application in the future which will address the issue of the appropriate level of funding, as well as the target, if any, associated with fuel-switching, and thus how success ought to be measured.

EGD submitted that in accepting the completely settled issues in this matter, the Board has effectively deferred the issue to a future panel of the Board that will consider it in the context of whatever proceeding any fuel-switching budget is brought forward.

In this Board Panel's view, making findings, providing guidance or even commenting on the substantive matters of fuel switching would not be appropriate. In making this finding, the Panel was mindful of the impact any conclusions may have on a future panel of the Board. Equally important, there was an insufficient evidentiary basis in this proceeding for the consideration of limiting fuel-switching to a TRC test only. Parties that believe that a TRC test should be used for a fuel-switching budget will have the opportunity to raise this issue in future rate proceedings.

What is the appropriate role of gas utilities in electric CDM? (Issue 15.1)

There was no settlement (complete or partial) on this issue.

EGD submitted that it would like to have the flexibility to make its expertise in DSM available in the electric Conservation and Demand Management (CDM) arena. It also stated that it was not planning to engage in CDM consulting. Union stated that it does not plan to engage in electric CDM. However, Union supported EGD's submissions.

SEC stated that on the assumption that the utilities can engage in electric CDM activities under the Undertakings given to the Lieutenant Governor in Council (the "Undertakings"), it supported the idea that the gas utilities be able to do joint programs with the electric LDCs, as this would tend to lower costs for the gas utilities. SEC cautioned against diverting the gas utilities' attention from gas DSM programs to electric CDM since the latter is, in SEC's view, more lucrative. CCC noted that there is no like thinking by the two utilities on their role regarding DSM activities and that there is no necessary and rational connection between electricity CDM and the utility DSM programs; therefore, there is a need to impose some constraints on the utilities' activities. CCC also questioned the legality of the gas utilities engaging in these activities without proper dispensation under the Undertakings. GEC submitted that gas utilities should only engage in electric CDM when it enhances gas DSM; otherwise, it would be a competing demand on scarce resources and a distraction from their primary focus. VECC supported co-delivery of DSM and CDM measures as it would reduce program costs, but not on the basis of incremental costing and profit sharing. LPMA and VECC suggested that electric CDM should be considered a non-utility activity for revenue requirement purposes of the distribution business.

EGD responded that it does not need an order or dispensation from the Board to engage in electric DSM. It specifically noted that gas DSM itself already generates electricity TRC savings which are included in the SSM calculations. EGD also stated that CDM is consistent with the objectives set out in the Ontario Energy Board Act to promote energy conservation; the Act does not limit the objective to simply natural gas. Further, this matter was canvassed in the EGD's EB-2005-0001 rate case where the Board approved the 50/50 earnings sharing mechanism for the joint participation in the TAPS electric CDM program.

The Board considers that the regulatory construct in Ontario is the concept of a pure distribution utility. This is manifested in the Undertakings and in the Board's rulings for some time. Gas DSM has remained an activity within the corporate structure of the utility and there is no compelling reason to alter this at this time - neither the utilities nor the intervenors instigated or sought a change with respect to gas DSM.

Recent developments in electric CDM may likely bring opportunities for gas utilities to engage or enhance engagement in this area. EGD has some minor engagements with Toronto Hydro Electric Systems Limited ("THESL"). Union does not appear to have any immediate plans to enter the electric CDM field. EGD, however, is interested in possibly expanding its electric CDM role where it is appropriate to do so.

There appears to be strong support if not consensus that the gas utilities should be permitted to engage in electric CDM if such engagement brings about cost efficiencies and the clear focus of the utility's demand management activities should relate to gas. The concern that attention may be diverted from gas DSM to electric CDM is, in the Board's view, theoretical at this stage. It is not axiomatic that enhanced engagement in electric CDM by the gas utilities will necessarily result in lost opportunities for gas DSM. The two initiatives can co-exist in an optimal and workable fashion. This is especially the case where demand management involves funding initiatives, not infrastructure, which has been the experience thus far.

The Board therefore is not concerned about the gas utilities in their present corporate structure engaging in electric CDM as long as such activities can be reasonably viewed as complementary and ancillary to gas DSM and do not involve investments in infrastructure. An example of that is EGD's involvement with THESL in the TAPS program. In fact, the utilization of the demand management expertise residing in the gas utilities should be viewed positively from a public interest perspective given the well known challenges in the Province's electricity sector. In that regard, engagement by the gas utilities in programs aimed at switching from electricity to gas is encouraged.

The concern arises if the gas utilities undertake stand-alone electric CDM activities. That is, programs that are not or do not appear to be synergetic to or enhancing gas DSM, especially if they involved investments in infrastructure on account of electric CDM. This would alter the regulatory construct of a gas distribution utility which would necessitate a review under the Undertakings and the Board's regulatory policies.

The Board is hampered in its assessment of the appropriate role for gas utilities in these situations. The Board is concerned about granting what might be viewed as blanket approval for the utilities to engage in electric CDM activities without knowing exactly what types of activity this might entail. For example, it is not clear if the gas utilities would bid for participation in the recently announced $400 million in OPA funding for electric CDM programs. As noted, the Board would not be concerned about gas utility involvement in OPA-funded programs targeted at switching from electricity to gas. The Board's concerns are in connection with stand-alone electric CDM programs where the gas utilities take on a central role.

This leads to the issue of whether relief from the Undertakings is required for the utilities to engage in electric CDM. EGD's current CDM activities with THESL were approved in EGD's most recent rates case. This program, however, is clearly incidental to EGD's DSM activities and it does not entail a separate infrastructure. EGD is free to continue its relationship with THESL regarding the TAPS program, and either gas utility may engage in similar programs with other electric LDCs where the CDM activity is clearly incidental to the utilities' DSM activities, or to engage in electric CDM stand-alone programs aimed at switching from electricity to gas where no dedicated investment in electric infrastructure would be required.

However, it is certainly possible that some other electric CDM activities or programs would require relief from the Undertakings. The Board is not in a position to articulate these engagements. The Board has not heard sufficient evidence to determine what would be an appropriate involvement by the gas utilities in such circumstances. The Board will leave it to the utilities to make such proposals if they so wish when they come forward with their respective DSM plans.

What is the appropriate treatment of costs and revenues for electric CDM? (Issue 15.2)

and

What incentives, if any, should be paid for electric CDM activities? (Issue 15.3)

There was no settlement (complete or partial) on these issues.

The utilities proposed that the costing of electric DSM should be on an incremental basis and the net revenues be split 50/50 between shareholders and ratepayers. This is the current practice for the TAPS program between EGD and THESL which was approved in the EB-2005-0001 rate case decision.

Some intervenors argued for full costing on the basis that it would avoid concerns about cross-subsidy between gas and electricity ratepayers. Full costing would also lower the net revenues to be split, thereby reducing the utilities' incentive to divert resources from DSM to CDM activities that may be more lucrative.

The Board notes that there was no opposition by intervenors to the institution of the 50/50 net revenue split proposal. The Board accepts the proposal as reasonable.

The utilities’ proposal to use incremental costing is not acceptable to the Board. Full costing has been the general practice for programs that are not part of the core utility business and the Board sees no reason to deviate from that practice in this case. Full costing avoids cross-subsidization from gas to electricity ratepayers and reduces the incentive to shift resources from gas DSM to electric CDM in pursuit of possibly more lucrative returns in the latter.

Having approved the incentives contained in the “financial package”, the Board does not see the need for other incentives necessary or appropriate for gas utilities to engage in electric CDM activities at this time.

CHAPTER 5 – INPUT ASSUMPTIONS, COMMON GUIDE, AND NEXT STEPS

In this chapter the Board addresses Issue 3.2 which is whether there should be a common guide to specify what input assumptions should be used by the utilities, and deals with the next steps of this proceeding.

Prior to and during the oral hearing the Board indicated that the process of listing and valuing input assumptions would not be part of this phase of the proceeding and that the Board wished to hear from parties on the appropriate subsequent process.

Issue 3.2 was phrased as, should there be a common guide (e.g. TRC Guide for Conservation and Demand Management ("CDM")) to specify what input assumptions should be used by the utilities?

All intervenors agreed as follows:

> "No. The input assumptions should be included in each utility's plan, and should be updated for each Utility during the plan period in accordance with the partial settlement to issue 3.1."

The utilities endorsed the notion of a common list and common values (where appropriate) of input assumptions for the two utilities in a common document. They suggested that this document would be an appendix to a Guide document which would reflect the Board's decision and convert elements of the decision into an operational handbook. They argued that this would be consistent with the intent of the proceeding to develop a rules-based framework for DSM. The utilities further suggested that Board Staff could take ownership of the development of the Guide and become the custodian for future updates.

The utilities argued that the creation of a common document has several advantages. Many of the input assumptions are common and they could be updated in their entirety by a Board process every three years. There would be no question as to the input assumptions that the utilities are to use. Assigning Board Staff the responsibility of updating the input assumptions would impart discipline on parties seeking to change the input assumptions. The utilities noted that where there was a need for different input assumptions between EGD and Union, it would not be difficult to effect within the list.

SEC argued that common input assumptions was a non-issue since the process for amending and updating the assumptions is completely settled in issues 3.1, 3.3 and 3.4 and that the existence of a guide is not relevant to the inclusion or determination of input assumptions. GEC endorsed SEC's view and further argued that an input assumptions process may frustrate the settlement on those issues. GEC further suggested that the Board should rely upon the evaluation and audit process to consider input assumptions. Energy Probe endorsed the submissions put forward by GEC and SEC. LPMA submitted that each utility should include its input assumptions as part of its own plan but the utilities should work together to develop common input assumptions where appropriate. Some argued that translating the Board's decision into a guide amounted to a waste of time, and unless the Board drafted the Guide and handed it to parties in a finished version, parties would take the opportunity to re-argue issues in interpreting the Board's decision.

In the Board's view it is clear that TRC input assumptions will have to be determined before any DSM plans can be finalized. The Board also agrees that the process should be conducted under the Board's review as a second phase to the current proceeding. The Board feels that the most appropriate process for creating the input assumptions guide is one similar to that employed to create the CDM Handbook. The Board therefore directs Board Staff to circulate a draft of an input assumptions guide. Parties will be given an opportunity to comment on the draft and, where they feel it necessary, to make submissions for changes with appropriate support. A Procedural Order will be issued which will set out the details of this process more fully. It is anticipated that this second phase to the proceeding will be completed before the end of 2006.

There are no persuasive reasons in the Board’s view not to have a common list of input assumptions and common values with the exceptions of the values as noted in this decision. In fact it appears to the Board that there are efficiencies to be gained by the use of a common set of assumptions. To the extent that there may be differences in how the assumptions might apply to the two utilities or in the values themselves as allowed in the decision, these could be accommodated and highlighted within the generic set. There are only two gas utilities affected and it would not be administratively difficult to do so.

Once the initial list and measures of the input assumptions is determined, the issue then becomes: what is the process for updating these?

The completely settled issue 3.1 stipulates that the input assumptions will be updated on a regular basis during the plan period as part of each utility’s ongoing evaluation and audit process. The Board has the ultimate authority to review and approve any changes. It appears to the Board that unless there is joint utility participation, the updates may occur at different times. This would not be efficient and would burden the regulatory process needlessly. The Board therefore concludes that the updating process should be centralized within Board Staff, at least for this first generation of multi-year DSM plans. The Board anticipates that the recommendations that come from the evaluation and audit committee would, in effect, be the substance of the comments process to be employed for the updating of the list and values of the input assumptions. Any suggested updates to the input assumptions guide arising from the evaluation and audit process should be filed with the Board within one month of the end of the annual audit and evaluation. The suggested updates will be considered by the Board, and the guide will be updated if the Board decides it is necessary. Further Procedural Orders may be issued regarding updates to the guide.

The next issue is whether there should be a handbook.

While the Board sees the merits in having a stand-alone handbook, it has concluded that this initiative should not be undertaken at this time. In making this finding, the Board is cognizant of the time sensitivity and significant effort that will be required to develop the common list and measures of the input assumptions and the Board does not wish parties be distracted by the effort to develop a handbook at this time.

The Board will issue a Procedural Order commencing the next phase that will lead into the determination of the input assumptions. The role of Board Staff will be set out in that procedural order. Further Procedural orders will be issued as required from time to time for the Board to receive and rule in this matter and to cause the filing of the multi-year DSM plans by the utilities.

Intervenors eligible for cost awards shall file their cost claims by September 15, 2006. The utilities may comment on these claims by September 22, 2006. The cost award applicants may respond to the utilities' comments by September 29, 2006. Union and EGD shall pay in equal amounts the intervenor costs to be awarded by the Board in a subsequent decision, as well as any incidental Board costs.

Dated at Toronto, August 25, 2006

Original Signed By

Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

Paul Vlahos
Member

Original Signed By

Ken Quesnelle
Member

APPENDIX 1

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0021

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

THE PROCEEDING

On February 15, 2006, the Board issued a Notice of Application that was published.

The Board issued Procedural Order No.1 on March 2, 2006, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- EDGI and Union evidence filed by April 10, 2006;
- Issues conference on April 24, 2006;
- Issues Day on April 28, 2006;
- Technical Conference to replace interrogatories on EDGI and Union's evidence on May 11 and 12, 2006;
- Intervenor (non-utilities) evidence filed by June 1, 2006;
- Technical Conference to replace interrogatories on Intervenor (non-utilities) evidence on June 8, 2006;
- Half day Intervenor Conference on June 19, 2006;
- Settlement Conference beginning June 19, 2006;
- Settlement Proposal by June 28, 2006; and
- Board review of Settlement Proposal on July 6, 2006.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- Malcolm Rowan on behalf of Canadian Manufactures and Exporters (“CME”);
- Paul Chernick on behalf of the School Energy Coalition (“SEC”);
- Chris Neme on behalf of the Green Energy Coalition (“GEC”); and
- Roger Colton on behalf of Low Income Energy Network (LIEN”).

On April 28, 2006, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

On June 12, 2006, Procedural Order No. 3 was issued as a result of there not being adequate time to complete the questions on CME evidence within the one day Technical Conference. The Board ordered CME to provided written responses to SEC and GEC questions.

Procedural Order No. 4, issued June 28, 2006, provided the parties with an extension to file a Settlement Proposal with the Board.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board’s offices.

Union Gas Limited (“Union”)	Crawford Smith
Enbridge Gas Distribution (“EGD”)	Dennis O’Leary
Board Counsel and Staff	Michael Millar Michael Bell Stephen McComb
Canadian Manufacturers & Exporters (“CME”)	Brian Dingwall

Consumers Council of Canada (“CCC”)	Robert Warren
Energy Probe	Norm Rubin
Green Energy Coalition (“GEC”)	David Poch
Industrial Gas Users Association (“IGUA”)	Vince DeRose
London Property Management Association (“LPMA”)	Randy Aiken
Low Income Energy Network (“LIEN”)	Juli Abouchar
Pollution Probe	Murray Klippenstein
School Energy Coalition (“SEC”)	Jay Shepherd
Vulnerable Energy Consumer’s Coalition (“VECC”)	Michael Buonaguro

WITNESSES

There were 11 witnesses who testified at the oral hearing. The following EGD and Union employees appeared as witnesses at the oral hearing:

EGD

Susan Clinesmith	Manager, Business Markets
Norman Ryckman	Group Manager, Business Intelligence and Support
Michael Brophy	Manager, DSM and Portfolio Strategy
Patricia Squires	Manager, Mass Markets and New Construction Market Development

Union

Chuck Farmer	Director, Market Knowledge and DSM
Tracy Lynch	Manager, DSM

In addition, EGD called the following witness:

Dr. Daniel M. Violette	Principal and Founder, Summit Blue Consulting

Witnesses called by intervenors at the oral hearing:

Chris Neme (By GEC)	Director of Planning and Evaluation, Vermont Energy Investment Corporation
Malcolm Rowan (By CME)	President, Rowan and Associates Inc.
Roger D. Colton (By LIEN)	Consultant, Fisher, Sheehan & Colton

In addition, CME called the following witness:

Anthony A. Atkinson	School of Accountancy, University of Waterloo