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November 7, 2014

VIA COURIER, EMAIL AND RESS

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Natural Resource Gas
Board File No. EB-2014-0274

We are counsel to Integrated Grain Processors Co-operative Inc. ("**IGPC**").

Pursuant to Procedural Order No. 2 dated October 20, 2014, please find attached the Document Brief of IGPC, which includes all materials that IGPC intends to rely upon at the oral proceeding on November 11, 2014.

Two hard copies of the Document Brief are being forwarded to the Board via courier.

If there are any questions, please contact the undersigned.

Yours very truly,

AIRD & BERLIS LLP

Scott Stoll

Scott Stoll

SAS/bm

cc: Applicant and Applicant's Counsel *(via email)*
Case Manager, Khalil Viraney *(via email)*
Board Counsel, Michael Miller *(via email)*

Attach

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas effective October 1, 2014.

DOCUMENT BRIEF OF INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

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ONTARIO ENERGY BOARD

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

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DOCUMENT BRIEF INDEX

SETTLEMENT AGREEMENT

NATURAL RESOURCE GAS LIMITED

2011 RATES APPLICATION
(EB-2009-0018)

AUGUST 18, 2010

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PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the "Board") in connection with an application by Natural Resource Gas Limited ("NRG") pursuant to section 36 of the *Ontario Energy Board Act, 1998* for an order or orders approving or fixing just and reasonable rates for the distribution of natural gas (EB-2010-0018).

Pursuant to Procedural Order No. 3 in this proceeding, a Settlement Conference was held on June 14, 15 and 28, 2010 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* (the "Settlement Guidelines"). This Settlement Agreement arises from the Settlement Conference and is for the consideration of the Board in its determination of NRG's 2011 natural gas distribution rates.

The Parties

NRG and the following intervenors (collectively the "Participating Intervenors"), as well as Ontario Energy Board staff ("Board Staff"), participated in the Settlement Conference in respect of all issues contained in this proposal:

- Town of Aylmer ("Aylmer")
- Vulnerable Energy Consumers Coalition ("VECC")
- Integrated Grain Processors Cooperative Inc. and IGPC Ethanol Inc. ("IGPC")

NRG and the Participating Intervenors are collectively referred to herein as the "Parties". In accordance with page 5 of the Settlement Guidelines, Board Staff is neither a Party nor a signatory to this Settlement Agreement. Although Board Staff is not a party to this Settlement Agreement, the Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

Further, Union Gas Limited is a registered intervenor in this proceeding, but did not participate in the Settlement Conference and takes no position on any of the issues herein.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The parties agree that all positions, negotiations and discussions of any kind whatsoever which took place during the Settlement Conference and all documents exchanged during the conference which were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

Summary of the Proposed Settlement

For the purposes of organizing this Settlement Agreement the Parties have followed the Issues List consented to by parties and attached as Appendix B to Procedural Order No. 2 in this proceeding. During the Settlement Conference, the Parties agreed to make one minor change to the Issues List to remove the year "2009" from item 6 under Issue 2 (Rate Base) such that this item reads as follows:

"6. Are amounts related to the IGPC pipeline added to rate base appropriate?"

The Parties wish to inform the Board that a number of the items in Issue 1 (Administration), Issue 2 (Rate Base), Issue 3 (Operating Revenue), Issue 4 (Cost of Service) and Issue 8 (Rate Design) have been settled in the following manner, and with the specified exceptions:

- Issue 2 (Rate Base): There has been no settlement on Issue 2.6 (appropriateness of amounts related to the IGPC pipeline added to rate base).

- Issue 3 (Operating Revenue): The Parties have reached agreement on all items, subject to NRG making certain changes to its customer addition forecasts (as outlined below).

- Issue 4 (Cost of Service): Issues 4.6, 4.11, 4.12 and 4.13 are unsettled. With respect to Issues 4.2 through 4.5 (inclusive), the Parties have reached agreement on these items subject to NRG making certain changes to its applied-for costs.

- Issue 8 (Rate Design): Generally speaking, the Parties have no disagreement as to rate design issues, but certain issues (notably, Issues 8.1 and 8.5) are contingent on settlement or disposition of the application as a whole.

Prior to the negotiated Settlement Agreement, the claimed net revenue deficiency, after adjustments and corrections made by NRG was $350,282 (taking into account adjustments made during information request and Technical Conference). As a result of the Settlement Agreement, the new claimed net revenue deficiency is $163,418. The change in revenue deficiency is shown in the Continuity Schedule attached as Appendix A to this Settlement Agreement. The bill impacts (expressed as a percentage change from NRG's current rates) associated with the revised revenue deficiency are shown on Appendix B to this Settlement Agreement The new claimed revenue deficiency (and bill impacts) may be affected by the Board's determination of the outstanding issues. Additionally, the resolution of unsettled issues by the Board may have an effect on settled issue; by way of example, issue 4.10 indicates that the forecast of income taxes is a fully settled issue, however the Board's decision on Cost of Capital and other unsettled issues may have an effect on the forecast of income taxes that the parties acknowledge will be accounted for in the final revenue requirement.

Details as to each Issue are set out in this Settlement Agreement. Issue 5 (Cost of Capital), Issue 6 (Rate of Return), Issue 7 (Cost Allocation) and Issue 9 (Incentive Regulation Mechanism) remain unsettled.

Through this Settlement Agreement, NRG agrees to certain changes from its original application for 2011 gas distribution rates filed with the Board and dated February 10, 2010. The most significant matters arising from this Settlement Agreement are as follows:

- Customer Additions: NRG initially forecasted only 1 new R1 industrial customer in the 2010 Bridge Year. To date in the Bridge Year, 13 new R1 industrial customers have been added and an additional four are forecast before October 1, 2010. The Parties have agreed that NRG's 2011 Test Year customer count for the R1 industrial rate class will be adjusted to add an additional 16 new customers (for the entire Test Year). The parties have also agreed on forecasted revenues from these 16 customers based on the average monthly consumption of the 13 customers added thus far during the 2010 Bridge Year, which will reduce the test year revenue deficiency by $4,195.

- Operations and Maintenance Expenses: NRG initially forecasted its 2011 Operations and Maintenance Expenses at $2,859,299 (per April 2010 evidence update). The Parties have agreed that NRG's 2011 Operations and Maintenance Expense will be $2,710,839. This revised figure includes reductions to NRG's Regulatory Costs, Advertising Expenses, Bad Debts and Management Fees that are set out in more detail below. While the reduction was arrived at via discussions regarding individual line items, nothing in this Settlement Agreement prevents NRG from managing its Operations and Maintenance Expenses as it deems appropriate on the basis of the global Operations and Maintenance Expenses amount. This settlement on Operations and Maintenance Expense includes all amounts included by NRG within its 2011 Operations and Maintenance Expenses (at Exhibit D8, Tab 3, Schedule 1) with the exception of expenses related to maintenance of the pipeline to serve IGPC.

The Settlement Agreement describes the agreements reached on the settled issues and identifies the parties who agree, or alternatively who take no position on each issue. The Settlement Agreement provides a direct link between each issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings on the settled issues.

Best efforts have been made to identify all of the evidence that relates to each settled issue. NRG's responses to information requests ("IR") is described by citing the name of the Party and the number of the interrogatory (e.g., Board Staff IR8). The identification and listing of the evidence that relates to each issue is provided to assist the Board, and is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

All of the issues contained in this proposal have been settled by the Parties as a package and none of the provisions of these issues are severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this Settlement Agreement. The distinct issues addressed in this proposal are interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not, prior to the commencement of the hearing of the evidence, accept the package in its entirety, then there is no settlement (unless the Parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Agreement). None of the Parties can withdraw from this proposal except in accordance with Rule 32.05 of the Rules. Moreover, the settlement of any particular issue in this proceeding and the positions of the Parties in this Settlement Agreement are without prejudice to the rights of the Parties to raise the same issue and/or to take any position thereon in any other proceeding.

The Parties agree that this Settlement Agreement forms part of the record in EB-2010-0018.

ISSUES

1. Administration

1.1 Has NRG complied with the OEB Directives as noted in NRG's 2007 Decision with Reasons?

Complete Settlement: There is an agreement to settle this issue as follows:

In NRG's last rate proceeding (EB-2005-0544), NRG was directed to: (a) prepare a vehicle fleet policy; and (b) consider developing a contingency plan "to address possible reduction in volumes as well as a potential loss of the entire rate class." NRG established a fleet policy on July 31, 2009, after reviewing the fleet policies of other gas and electric utilities. The fleet policy can be found at Appendix A to Exhibit A1, Tab 4, Schedule 1 of the pre-filed evidence. With respect to a contingency plan to address declining volumes in NRG's Rate 2, NRG has developed a plan to close Rate 2 to new entrants and transfer NRG's Rate 2 customers to Rate 4. Eventually, Rate 2 would be eliminated.

In EB-2008-0106, the Board directed NRG to file a proposal to move to an incremental cost based system gas fee. NRG's evidence at Exhibit A1, Tab 4, Schedule 1 sets out the adjustments made to NRG's fully allocated cost model in order to move to an incremental system gas fee.

For the purpose of obtaining settlement, the Parties agree that NRG has complied with the OEB Directives as noted in EB-2005-0544 and EB-2008-0106.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

A1/4/1 Status Report on OEB Directives (Fleet Policy, p.1 & Appendix A)
A1/4/1 Status Report on OEB Directives (Contingency Plan, p.1 through 5)
A1/4/1 Status Report on OEB Directives (System Gas Fee, p. 5 through 6)
Undertaking No. JT1.17 (Contingency Plan)

1.2 Has NRG amended its security deposit policy as directed in the Board's EB-2008-0413 Decision?

Complete Settlement: There is an agreement to settle this issue as follows:

In the Board's Decision in EB-2008-0413 (May 5, 2009), NRG was ordered to amend its security deposit policy by July 6, 2009 in accordance with Appendix B to the Board's Decision. NRG made these amendments in June 2009, and incorporated them into section 1.2 of NRG's Natural Gas Service Rules & Regulations, which was filed at Exhibit A1, Tab 5, Schedule 1 of the pre-filed evidence in this proceeding. In response to an information request from Board Staff (Board Staff IR3), a typographical error was discovered. In its response to Board Staff IR3, NRG corrected the typographical error and included the amended page in its response. For the purpose of obtaining settlement, the Parties agree that NRG has amended its security deposit policy in accordance with the Board's direction in EB-2008-0413.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

A1/5/1 Natural Gas Service Rules & Regulations (revised October 1, 2009)
Board Staff IR3

1.3 Are NRG's audited financial statements from 2006 to 2009 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining settlement, the Parties agree to accept NRG's audited financial statements from 2006 to 2009 where applicable. IGPC's acceptance of the audited financial statements is without prejudice to its issue regarding the IGPC pipeline.

Approval:

Parties in Support: NRG, VECC

Parties Taking No Position: IGPC, Aylmer

Evidence: The evidence in relation to this issue includes the following:

A3/1/1 NRG Financial Statements (September 30, 2009)
A3/1/2 NRG Financial Statements (September 30, 2008)
A3/1/3 NRG Financial Statements (September 30, 2007)

A3/1/4 NRG Financial Statements (September 30, 2006)
Board Staff IR7
Aylmer IR1, IR2 and IR5 through 11
VECC IR1 through IR6
IGPC IR1 and IR6 through IR8

2. Rate Base

2.1 Are the amounts proposed for Rate Base in 2010 and 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

Subject to issue 2.6 below (amounts related to IGPC pipeline added to rate base), for the purpose of obtaining settlement, the Parties agree that the amounts proposed for Rate Base in 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B1/1/1 Rate Base
VECC IR20 and IR21

2.2 Were the amounts closed (or proposed to be closed) to Rate Base in 2008 and 2009 prudently incurred in view of the fact that not all amounts received OEB scrutiny?

Complete Settlement: There is an agreement to settle this issue as follows:

Subject to issue 2.6 below (amounts related to IGPC pipeline added to rate base), for the purpose of obtaining settlement, the Parties agree that amounts closed (or proposed to be closed) to Rate Base in 2008 and 2009 were prudently incurred.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B5/1/1	Summary of Utility Rate Base – 2008 Actual
B5/2/1	Utility Capital Expenditures – 2008 Actual
B5/2/2	Capital Projects – 2008 Actual
B5/2/3	Aggregate Cost/Benefit Ratio – 2008 Actual
B5/2/4	Financial Tests – 2008 Actual
B6/1/1	Summary of Utility Rate Base – 2009 Actual
B6/2/1	Utility Capital Expenditures – 2009 Actual
B6/2/2	Capital Projects – 2009 Actual
B6/2/3	Aggregate Cost/Benefit Ratio – 2009 Actual
B6/2/4	Financial Tests – 2009 Actual

Board Staff IR7
VECC IR7 through IR17

2.3 Is the forecast level of capital spending in 2010 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining settlement, the Parties agree that the forecast level of capital spending in 2010 ($730,840) is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B7/1/1	Summary of Utility Rate Base – 2010 Bridge
B7/2/1	Utility Capital Expenditures – 2010 Bridge
B7/2/2	Capital Projects – 2010 Bridge
B7/2/3	Aggregate Cost/Benefit Ration for Main Additions – 2010 Bridge
B7/2/4	Financial Tests – 2010 Bridge

Board Staff IR6, IR8 and IR9
VECC IR16 through IR18

2.4 Is the forecast level of spending for 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining settlement, the Parties agree that the forecast level of capital spending in 2011 ($810,004) is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B8/1/1	Summary of Utility Rate Base – 2011 Test
B8/2/1	Utility Capital Expenditures – 2011 Test
B8/2/2	Capital Projects – 2011 Test
B8/2/3	Aggregate Cost/Benefit Ration for Main Additions – 2011 Test
B8/2/4	Financial Tests – 2011 Test

Board Staff IR6 and IR8
VECC IR 19 and 20

2.5 Is the working capital allowance for 2010 and 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining settlement, the Parties agree that the working capital allowance for 2010 ($294,641) and 2011 ($224,340) is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B7/4/1	Allowance for Working Capital – 2010 Bridge
B7/4/2	Cash Requirements for Working Capital – 2010 Bridge
B8/4/1	Allowance for Working Capital – 2011 Test
B8/4/2	Cash Requirements for Working Capital – 2011 Test

Board Staff IR10

2.6 Are amounts related to the IGPC pipeline added to 2009 rate base appropriate?

Partial Settlement: There is an agreement to settle these two issues as follows:

This issue remains largely unsettled. However, during the Settlement Conference, the Parties agreed to two modifications:

- To amend the wording of this issue (as stated) by removing "2009" such that this issue now reads: "Are amounts related to the IGPC pipeline added to rate base appropriate?"

- The Parties agreed to reduce the pipeline capital costs by $26,000 to take into account an error in method of calculating interest on management time spent on the pipeline.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

B6/2/1 Utility Capital Expenditures – 2009 Actual
Technical Conference Transcript, p.23, line 9, to p.24, line 19
Board Staff IR11
IGPC IR18 and IR22

3. Operating Revenue

3.1 Is the customer addition forecast for 2010 appropriate?

3.2 Is the customer addition forecast for 2011 appropriate?

Complete Settlement: There is an agreement to settle these two issues as follows:

For the purpose of settlement, the Parties agree that an additional 16 R1 industrial customers will be added to NRG's R1 industrial rate class forecast for the entire 2011 Test Year. In its application, NRG forecasted only 1 new R1 industrial customer in the Bridge Year. To date in the 2010 Bridge Year, 13 new R1 industrial customers have been added and an additional four are forecast to be added before October 1, 2010. The Parties agree that all other customer additions forecast for 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

C7/2/1 Summary of Gas Sales and Transportation – 2010 Bridge
C7/2/2 Customers by Rate Class – 2010 Bridge
C7/2/4 Monthly Throughput Data – 2010 Bridge Customers, Volumes, Revenues

C7/2/5 Average Gas Consumption per Customer – 2010 Bridge
C8/2/1 Summary of Gas Sales and Transportation – 2011 Test
C8/2/2 Customers by Rate Class – 2011 Test
C8/2/4 Monthly Throughput Data – 2011 Test Customers, Volumes, Revenues
C8/2/5 Average Gas Consumption per Customer – 2011 Test
Board Staff IR12
Undertaking No. JT1.11

3.3 Is the volume throughput and revenue forecast appropriate for 2010 and 2011?

Complete Settlement: There is an agreement to settle this issue as follows:

Based on the amendments made to the customer additions forecast noted in issues 3.1 and 3.2 above, the Parties have also agreed to amend the forecasted volume throughput for (and forecasted revenues from) these 16 customers based on the average monthly consumption of the 13 customers added thus far during the 2010 Bridge Year. Consequently, the forecasted volumes from the R1 (industrial) rate class is increased by 1,419 m^3 each month in the 2011 Test Year. The revenue effect of these customer additions is to reduce the 2011 Test Year revenue deficiency by $4,195 (before tax).

The volume throughput for IGPC (proposed Rate 6) is based on IGPC's contracted volume.

For the purpose of obtaining settlement, the Parties have agreed that the volume throughput and revenue forecasts for all other rate classes for 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

C1/1/1 Operating Revenue
C1/1/3 Throughput Volume
C7/1/1 Operating Revenue – 2010 Bridge
C7/1/2 Summary of Operating Revenue – 2010 Bridge
C7/1/3 Gross Margin Analysis by Sales Class – 2010 Bridge
C7/2/1 Summary of Gas Sales and Transportation – 2010 Bridge
C7/2/3 Gas Sales and Transportation Volume – 2010 Bridge vs. 2009 Actual
C7/2/4 Monthly Throughput Data – 2010 Bridge Customers, Volumes, Revenues
C7/2/5 Average Gas Consumption per Customer – 2010 Bridge
C8/1/1 Operating Revenue – 2011 Test
C8/1/2 Summary of Operating Revenue – 2011 Test

C8/1/3 Gross Margin Analysis by Sales Class – 2011 Test
C8/2/1 Summary of Gas Sales and Transportation – 2011 Test
C8/2/3 Gas Sales and Transportation Volume – 2011 Test vs. 2010 Bridge
C8/2/4 Monthly Throughput Data – 2011 Test Customers, Volumes, Revenues
C8/2/5 Average Gas Consumption per Customer – 2011 Test
Board Staff IR13
VECC IR22, IR23, and IR30
Undertaking No. JT1.11

3.4 Is the ancillary services revenue and return forecast appropriate for 2010 and 2011?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties agree that the ancillary services revenue and return forecast for 2010 and 2011 is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

C1/1/5 Rate of Return on Ancillary Services
C7/1/1 Operating Revenue – 2010 Bridge
C7/1/2 Summary of Operating Revenue – 2010 Bridge
C7/3/1 Rate of Return on Ancillary Services – 2010 Bridge
C8/1/1 Operating Revenue – 2011 Test
C8/1/2 Summary of Operating Revenue – 2011 Test
C8/3/1 Rate of Return on Ancillary Services – 2011 Test
VECC IR31 through IR34

3.5 Is the general service and contract forecast appropriate for 2010 and 2011?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties agree that the general service and contract forecast for 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

C1/1/5	Rate of Return on Ancillary Services
C7/1/1	Operating Revenue – 2010 Bridge
C7/1/2	Summary of Operating Revenue – 2010 Bridge
C7/3/1	Rate of Return on Ancillary Services – 2010 Bridge
C8/1/1	Operating Revenue – 2011 Test

4. Cost of Service

As noted above, the Parties have agreed to certain reductions to components of NRG's applied-for 2011 Test Year Operations and Maintenance Expenses (specifically, the NRG's Regulatory Costs, Advertising Expenses, Bad Debts and Management Fees). These specific reductions are discussed in detail below. Notwithstanding these specific reductions, the Parties acknowledge that nothing in this Settlement Agreement prohibits NRG from spending on operations and maintenance as it sees fit during either the 2011 Test Year or over the course of any approved IRM period.

4.1 Is the gas transportation cost forecast for 2010 and 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties agree that the gas transportation costs forecast for 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

D7/1/1	Cost of Service – 2010 Bridge
D7/1/2	Summary of Cost of Service – 2010 Bridge
D7/2/1	Cost of Gas – 2011 Test
D8/1/1	Cost of Service – 2011 Test
D8/1/2	Summary of Cost of Service – 2011 Test
D8/2/1	Cost of Gas – 2011 Test

4.2 Is the O&M cost forecast for 2010 and 2011 appropriate?

Partial Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties agree to reduce NRG's Test Year Operations and Maintenance Expense by $173,460. This reduction results from individual reductions to NRG's forecasted regulatory costs (described in Issue 4.4 below), advertising expenses (described in Issue 4.3 below), management fees (described in Issue 4.5 below), and bad debt expense. With respect to the bad debt expense, the Parties have agreed to reduce the bad debt expense for the 2011 Test Year by $15,000 (from $75,000 to $60,000). There was also a reduction to PST of $6,960 based on introduction of the harmonized sales tax.

This issue is only partially settled because the Parties have not reached agreement on the IGPC period costs (described in Issue 4.6 below).

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/1 Operating and Maintenance Costs
D1/3/3 Advertising Costs
D1/3/4 Management Fee
D1/3/6 Regulatory Costs
D1/3/7 IGPC Period Costs
D8/3/1 Operating and Maintenance Expense – 2011 Test
D8/3/2 Regulatory Expense – 2011 Test
Board Staff IR14, IR15 and IR16
VECC IR35 through IR37

4.3 Is the proposed advertising expense for 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed to reduce the advertising expense for the 2011 Test Year from $98,000 to $56,500. This represents a reduction of $41,500 which is made up of a $20,000 general reduction in the advertising expense and an additional $21,500 of forecasted expenses associated with NRG's proposed natural gas vehicle program.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/1 Operating and Maintenance Costs
D1/3/3 Advertising Costs
D8/3/1 Operating and Maintenance Expense – 2011 Test
Board Staff IR17
VECC IR38 and IR39
Undertaking No. JT1.13

4.4 Are the proposed regulatory costs for 2011 appropriate?

Complete (*Partial*) Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed to reduce the (adjusted) applied-for regulatory costs from $625,000 to $450,000. The consequent reduction on an annual basis is $35,000 (assuming the Board approves a five-year IR Plan).

A component of the regulatory costs included in rates and amortized over five years relate to ongoing administration of the proposed IR Plan. In the event that the Board approves an IR Plan for NRG that has a term shorter than five years, the Parties have agreed that regulatory costs included in rates should be reduced by $10,800 for each year the IR term is reduced (i.e., complete rejection of an IR Plan would reduce regulatory costs by $54,000; approval of a three year IR Plan for NRG would reduce regulatory costs by $21,600).

In the event that the Board does not approve a five-year IR Plan, the parties do not agree on the appropriate amortization period for the regulatory costs. Thus, if the Board approves a five-year IR Plan, then this Issue 4.4 is completely settled. If the Board approves an IR Plan for NRG that is shorter than five years, then the parties agree to have the Board determine the issue as to the appropriate amortization period for the regulatory costs.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/1 Operating and Maintenance Costs

D1/3/6 Regulatory Costs
D8/3/1 Operating and Maintenance Expense – 2011 Test
D8/3/2 Regulatory Expense – 2011 Test
Board Staff IR18
IGPC IR24

4.5 Are the management fees proposed for 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed to reduce the management fees for the 2011 Test Year from $235,157 to $220,157.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/1 Operating and Maintenance Costs
D1/3/4 Management Fee
D8/3/1 Operating and Maintenance Expense – 2011 Test
Board Staff IR19
VECC IR40 through IR43
Undertaking No. JT1.2

4.6 Are the IGPC period costs for 2010 and 2011 appropriate?

This issue remains unsettled.

4.7 Is NRG's proposed depreciation life for the IGPC pipeline appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the 20 year depreciation life for the IGPC pipeline is appropriate. The amount of depreciation will be dependant upon the capital cost approved by the Board to be taken into rate base; see Issue 2.6.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/7 IGPC Period Costs (see pages 3 through 5)
Board Staff IR21

4.8 Is the depreciation cost for 2010 and 2011 appropriate?

Partial Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the depreciation costs (as adjusted at the Technical Conference, as described below) for 2010 and 2011 are appropriate, with the exception of depreciation costs associated with the pipeline serving IGPC (and wholly allocated to IGPC). At the Technical Conference (in response to a question from VECC), NRG discovered a double-counting of the depreciation expense on water heater rentals. As outlined in Undertaking JT1.1, the correction of the double-counting reduced the deficiency in the 2011 Test Year by $180,012. This correction was filed with the Board on June 17, 2011.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/3/7 IGPC Period Costs (see pages 3 through 5)
D1/4/1 Depreciation
D7/1/1 Cost of Service – 2010 Bridge
D7/4/1 Depreciation Expense – 2010 Bridge
D7/4/2 Summary of Depreciation Expense – 2010 Bridge
D8/1/1 Cost of Service – 2011 Test
D8/4/1 Depreciation Expense – 2011 Test
D8/4/2 Summary of Depreciation Expense – 2011 Test
Technical Conference Transcript (Page 3, line 8 to Page 4, line 14)
Undertaking No. JT1.1

4.9 Are the property and capital tax forecasts for 2010 and 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the property and capital tax forecasts for 2010 and 2011 are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

D1/5/1 Property and Capital Taxes
D7/1/1 Cost of Service – 2010 Bridge
D7/5/1 Property and Capital Taxes – 2010 Bridge
D8/1/1 Cost of Service – 2011 Test
D8/5/1 Property and Capital Taxes – 2011 Test

4.10 Is the income tax forecast for 2010 and 2011 appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the income tax forecast for 2010 and 2011 are appropriate. A correction to the Capital Cost Allowance was made during the Settlement Conference. The correction (and income tax effect) is shown on the Continuity Schedule attached as Appendix A to this Settlement Agreement.

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

D1/6/1 Income Taxes
D7/1/1 Cost of Service – 2010 Bridge
D7/6/1 Income Taxes Payable – 2010 Bridge
D8/1/1 Cost of Service – 2011 Test
D8/6/1 Income Taxes Payable – 2011 Test
Board Staff IR22
IGPC IR53 and IR54

4.11 Are the proposals for deferral and variance accounts appropriate?

This issue remains unsettled.

4.12 Has NRG complied with the Board's Decision in EB-2005-0544 regarding its purchase of gas from the Affiliate company?

This issue remains unsettled.

4.13 Is the cost of gas from 2007 to 2011 appropriate?

This issue remains unsettled.

5. Cost of Capital

All cost of capital issues remain unsettled.

6. Rate of Return

The single rate of return issue remains unsettled.

7. Cost Allocation

All cost allocation issues remain unsettled.

8. Rate Design

8.1 Are the rates proposed in Exhibit H3, Tab 1, Schedule 1 appropriate?

Because this Settlement Agreement is not a complete settlement of all issues, this issue remains unsettled.

8.2 Is the proposal to increase the monthly fixed charges and the monthly customer charges across all rate classes appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the monthly fixed charges and the monthly customer charges across all rate classes are appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

H1/1/1 Summary of Recommendations & Changes

8.3 Is the proposal to change the system gas fee component of the gas supply charge appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties have agreed that the proposal to change the system gas fee component of the gas supply charge is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

A1/4/1 Status Report on Ontario Energy Board Directives (pages 5 and 6)

8.4 Is NRG's proposal for Rate 2 Class customers appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

For the purpose of obtaining a settlement, the Parties agree that NRG's proposal for Rate 2 Class customers is appropriate.

Approval:

Parties in Support: NRG, VECC, IGPC

Parties Taking No Position: Aylmer

Evidence: The evidence in relation to this issue includes the following:

A1/4/1 Status Report on Ontario Energy Board Directives (pages 5 and 6)

8.5 Is NRG's proposal to implement a new rate class for IGPC appropriate?

Complete Settlement: There is an agreement to settle this issue as follows:

Subject to Issue 8.1, for the purpose of obtaining a settlement, the Parties have agreed that the proposal to create a new rate class specific to IGPC is appropriate. The obligation to consider an application that would request Board approval for a rate specific to the customer characteristics of IGPC arose contractually in the Gas Delivery Contract between NRG and IGPC (see Part 3, page 3 of Gas Delivery Contract found at IGPC IR#12).

Approval:

Parties in Support: NRG, VECC, IGPC, Aylmer

Parties Taking No Position: —

Evidence: The evidence in relation to this issue includes the following:

IGPC IR#12

9. Incentive Regulation Mechanism

9.1 Is NRG's proposed five year Incentive Regulation ("IR") Plan appropriate?

9.2 Is NRG's proposal of including an all-in-one fixed price cap escalator of 1.5% during the IR term appropriate?

9.3 Is the term of the IR Plan appropriate?

9.4 Is NRG's proposal for Earnings Sharing Mechanism, Off-Ramps, Z-factors and Y-Factors under the IR Plan appropriate?

9.5 Is NRG's annual rate adjustment mechanism under the IR Plan appropriate?

These issues remains unsettled.

Appendix "A" to Settlement Agreement (EB-2010-0018)

Continuity Schedule

Natural Resource Gas Limited - 2011 Rates
Continuity Schedule

	(1) Per April Update	(2) Per Interrogatories	(2) - (1) Change Note 1	(3) Per Settlement & Technical Conference Corrections	(3) - (2) Change	(4) Per CCA correction	(4) - (3) Change	Comment
Utility Income								
Revenue								
Distribution Revenue	5,480,613	5,480,613	-	5,484,808	4,194	5,484,808	-	Increase to R1 Industrial Customers
Other Operating Revenue (Net)	664,160	671,856	7,696	851,867	180,012	851,867	-	Eliminate error on double counting depreciation
Total Revenue	6,144,773	6,152,469	7,696	6,336,675	184,206	6,336,675	-	
Costs and Expenses								
Gas Transportation Costs	732,331	732,331	-	732,360	30	732,360	-	Effect of additional R1 Industrial Customers
Operation & Maintenance	2,859,299	2,884,299	25,000	2,770,839	(113,460)	2,710,839	(60,000)	$6,960 HST impact on OM&A; $106,500 agreed reduction to OM&A
Depreciation & Amortization	1,206,523	1,184,232	(22,291)	1,182,932	(1,300)	1,182,932	(0)	Effect of reduction to Pipeline of $26,468 interest
Property & Capital Taxes	400,776	400,776	-	400,776	-	400,776	-	
Total Costs and Expenses	5,198,928	5,201,637	2,709	5,086,907	(114,730)	5,026,907	(60,001)	
Utility Income Before Income Taxes	945,845	950,832	4,987	1,249,767	298,936	1,309,768	60,001	
Income Taxes	50,252	46,428	(3,824)	111,083	64,655	213,787	102,704	CCA Correction - CCA taken twice on Ethanol Pipeline in error
Utility Income	895,593	904,404	8,811	1,138,684	234,281	1,095,981	(42,703)	
Deficiency								
Utility Rate Base	13,618,731	13,821,312	202,581	13,916,015	94,703	13,916,015	-	Change 1 to Working Capital re: Security Deposits
Indicated Rate of Return	6.58%	6.54%		8.20%		7.88%		
Requested/Approved Rate of Return	9.14%	9.08%		9.06%		9.05%		
(Deficiency)/Sufficiency in Return	-2.57%	-2.53%		-0.86%		-1.17%		
Net Revenue (Deficiency)/Sufficiency	(349,612)	(350,282)		(119,319)		(163,418)	(44,099)	
Provision for Income Taxes	(112,805)	(111,100)		(47,163)		(65,620)	(18,457)	
Gross Revenue (Deficiency)/Sufficiency	(462,417)	(461,382)		(166,482)		(229,038)	(62,556)	

Note 1 - changes incorporate the changes noted in the IR Responses ie error in automobilies

Appendix “B” to Settlement Agreement (EB-2010-0018)

Bill Impacts (Distribution)* (% change from EB-2005-0544 rate)	**EB-2010-0018 (per original filing)**	**EB-2010-0018 (per Settlement Agreement)**
Rate 1 (Residential) Rate 1 (Commercial) Rate 1 (Industrial)	5.93% 3.15% 3.96%	2.66% -1.60% -1.78%
Rate 2	0.73%	0.70%
Rate 3	0.35%	0.30%
Rate 4	-0.09%	-0.12%
Rate 5	1.91%	1.86%
Rate 6**	8.70%	10.53%

* Based on average consumptions shown at Exhibit C8, Tab 2, Schedule 5; and leaving the applicable Monthly Fixed Charges and Monthly Customer Charges as proposed by NRG at Exhibit H3, Tab 1, Schedule 1.

** There was no Rate 6 class in EB-2005-0544, so for purposes of this Appendix, the bill impacts are evaluated against Rate 3 (which is the rate that IGPC has been paid since coming into service).

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2010-0018

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

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

BEFORE: Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

DECISION AND ORDER

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

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

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

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

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

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

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

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

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

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

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

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

THE ISSUES

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

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

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

RATE BASE

Capital Cost of the IGPC Pipeline

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

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

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

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

Board Findings

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

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

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

Removal of Ancillary Business from Rate Base

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

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

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

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

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

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

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

Board Findings

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

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

COST OF SERVICE

IGPC Period Costs

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

Insurance

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

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

<u>Business Interruption Insurance</u>

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

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

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

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

Transfer Station Insurance

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

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

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

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

Pipeline Maintenance Costs

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Station Maintenance Costs

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

Board Findings

Insurance Costs

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

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

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

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

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

<u>Maintenance Costs</u>

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

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

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

Deferral and Variance Accounts

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

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

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

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

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

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

[4] Oral Hearing Transcript Volume 1, Page 112

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

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

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

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

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

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

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

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

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

Board Findings

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

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

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

Amortization Period of Regulatory Costs

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

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

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

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

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

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

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

Board Findings

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

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

NRG Gas Costs

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

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

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

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

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

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

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

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

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

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

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

Transportation Charge

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

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

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

NRG agreed to this proposal in Reply.

Engineering Study to Explore Alternatives

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

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

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

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

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

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

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

Deemed Application of the Affiliate Relationship Code

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

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

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

Board Findings

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

Transportation Charge

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

Refund of Overpayment of $97,000

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

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

Gas Contract Price Determination

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

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

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

Study to Explore Alternatives to Maintaining System Integrity

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

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

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

Application of ARC

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

COST OF CAPITAL

Capital Structure and Return on Equity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Board Findings

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

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

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

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

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

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

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

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

A fair or reasonable return on capital should:

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

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

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

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

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

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

Cost of Debt

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

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

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

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

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

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

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

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

Board Findings

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

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

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

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

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

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

Average Cost of Capital

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

COST ALLOCATION

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

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

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

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

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

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

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

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

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

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

Board Findings

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

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

EFFECTIVE DATE

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

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

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

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

COST AWARDS

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

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

THE BOARD ORDERS THAT:

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

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

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

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

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

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

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

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

DATED at Toronto, December 6, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2010-0018

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

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

BEFORE: Ken Quesnelle
Presiding Member

Paul Sommerville
Board Member

DECISION AND ORDER – PHASE 2
May 17, 2012

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

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

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

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

Phase 2 Proceeding

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

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

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

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

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

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

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

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

Cost of Gas Purchased from NRG Corp.

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

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

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

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

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

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

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

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

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

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

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

Board staff offered the following recommendations in its submission:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Board Findings

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

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

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

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

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

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

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

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

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

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[7] Undertaking J1.3

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

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

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

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

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

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

IGPC Revised Motion

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

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

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

ARTICLE IX – DISPUTE RESOLUTION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Board Findings

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

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

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

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

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

DATED at Toronto May 17, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

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

EB-2012-0406
EB-2013-0081

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 Integrated Grain Processors Co-operative Inc., pursuant to section 42(3) of the Ontario Energy Board Act, 1998, for an order requiring Natural Resource Gas Limited to provide gas distribution service; and

AND IN THE MATTER OF an Order to review capital contribution costs paid by Integrated Grain Processors Co-operative Inc., to Natural Resource Gas Limited pursuant to Sections 19 and 36 of the Ontario Energy Board Act 1998.

BEFORE: Marika Hare
Presiding Member

Christine Long
Board Member

Ellen Fry
Board Member

DECISION AND ORDER
February 27, 2014

Background

Natural Resource Gas Limited ("NRG") is a privately owned utility regulated by the Ontario Energy Board ("the Board") that sells and distributes natural gas within Southern Ontario. The utility is the sole supplier of natural gas to approximately 7,000 customers in the Town of Aylmer and surrounding areas. Integrated Grain Processors Co-operative Inc. ("IGPC") is a customer of NRG that operates an ethanol facility in Aylmer. In 2008, NRG built a dedicated pipeline to serve the IGPC ethanol plant pursuant to a leave to construct approval issued by the Board.

NRG and IGPC signed a Pipeline Cost Recovery Agreement ("PCRA") dated January 31, 2007. The PCRA provided for financial arrangements concerning the construction of the pipeline, which included that a financial contribution be provided by IGPC to NRG. The pipeline cost $8.65 million. As required by the PCRA, IGPC made a pre-construction payment to NRG of approximately $3.5 million as a contribution in aid of construction (also called a "capital contribution") and provided a letter of credit in the amount of $5.2 million to NRG. The capital costs of the pipeline would therefore be recovered by NRG from two sources: through its rates for distributing natural gas and from IGPC's direct $3.5 million capital contribution.

As discussed below, the PCRA included provisions to reconcile the amount of the capital contribution to actual costs and to reduce the letter of credit over time.

There are a number of issues in dispute between NRG and IGPC concerning these financial arrangements. IGPC submits that NRG should not have included certain costs in the capital costs of the pipeline and that IGPC's capital contribution should be reduced to reconcile the actual costs of the pipeline with estimated costs. Accordingly, IGPC is seeking a refund for a portion of the $3.5 million it provided to NRG for the capital contribution as stipulated in the provisions of the PCRA[1]. As well, IGPC seeks a reduction to the letter of credit amount in accordance with its interpretation of the PCRA.

IGPC is also seeking an order requiring NRG to provide it with gas service, pursuant to section 42(3) of the Act, which states: [u]pon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sale service".

[1] Section 3.13 of the PCRA

The history of previous proceedings in front of the Board concerning disputes between IGPC and NRG, leading up to this proceeding are contained at Appendix A.

This Proceeding

IGPC filed an application with the Board on October 11, 2012 (EB-2012-0406) seeking an order pursuant to section 42(3) of the Act requiring NRG to provide gas distribution services and gas sales to meet IGPC's facility expansion and upgrading plans. The application also sought various other forms of relief.

In response to this application, the Board initiated a proceeding to address IGPC's request under Section 42(3) of the Act. The Board granted the Town of Aylmer intervenor status in the proceeding. The Board also issued a letter dated February 13, 2013 indicating that some of the issues raised by IGPC would be addressed in a separate proceeding while some of the other issues were compliance related and have been referred to the Compliance Section of the Board.

As referenced above, a separate proceeding (EB-2013-0081) had been commenced to deal with the capital costs of the pipeline constructed for IGPC's ethanol plant.

The Board issued a Notice of Application on April 2, 2013 stating that it would combine the Section 42 proceeding (EB-2012-0406) and the proceeding that would review IGPC's capital contribution costs in respect of the pipeline (EB-2013-0081).

This decision is organized on the basis of the issues list approved by the Board for this proceeding in Procedural Order No. 2.

Issue 1: Is an Order of the Board requiring NRG to provide gas distribution services and gas sales to IGPC to meet its facility expansion and upgrading plans necessary and appropriate?

Background

In mid-2012, IGPC started to consider expanding its ethanol facility. This expansion would require additional gas supplies. On June 18th, IGPC wrote to NRG to request a meeting to discuss the expansion. NRG responded the same day asking that IGPC direct all non-urgent communications to NRG's president. On July 3rd, IGPC sent a second letter, this time to NRG's president, requesting a meeting to discuss the proposed expansion. On July 9th, NRG responded stating that "NRG can not enter into any discussions regarding possible new business or changes to existing business arrangements until major disagreements have been resolved" and that "Any future requests made by IGPC would have to include a method for IGPC to compensate NRG for the time spent and the out of pocket expenses that it occurs [*sic*]. These financial arrangements will have to be in place before any discussions will be entertained." On July 24th, NRG wrote to IGPC stating that because NRG had not heard further from IGPC, NRG was assuming that IGPC had chosen not to proceed with the expansion. IGPC responded the next day, stating that IGPC was "currently in preliminary engineering stages of an expansion to its facilities."[2] Subsequently, through invoices issued August 24th and September 27th, NRG charged IGPC approximately $7,000 for unspecified services in relation to IGPC's request for expansion.

Section 42(2) of the Act provides as follows:

Duty of gas distributor

> (2) Subject to the *Public Utilities Act*, the *Technical Standards and Safety Act, 2000* and the regulations made under the latter Act, sections 80, 81, 82 and 83 of the *Municipal Act, 2001* and sections 64, 65, 66 and 67 of the *City of Toronto Act, 2006*,
>
> a gas distributor shall provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building.
>
> Order
>
> (3) Upon application, the Board may order a gas transmitter, gas distributor or storage company to provide any gas sale, transmission, distribution or storage service or cease to provide any gas sale service.

[2] July 25, 2012 letter from IGPC to NRG, IGPC Pre-filed Evidence, Exhibit C, Tab 9, Page 2

Position of IGPC

IGPC has argued that by placing conditions on discussing further expansion of the gas pipeline, NRG has failed to meet its obligations under s. 42(2) of the Act. IGPC further argued that NRG had failed to meet the standard of good utility practice. IGPC submitted that it should have access to gas distribution services on a non-discriminatory basis.

IGPC argued that NRG could not use past disagreements between the two parties as a basis to delay, defer or deny any gas distribution services. IGPC noted that the disagreements referred to by NRG in its letter of July 9 appeared to be related to the capital cost of the IGPC pipeline, a libel suit filed by NRG against IGPC (which is not before the Board) and the amount of the letter of credit provided by IGPC in relation to the gas pipeline. IGPC also submitted that costs related to time spent by NRG to discuss the expansion, should not prevent IGPC from receiving service. Furthermore, IGPC submitted that it was willing to compensate NRG for its reasonably incurred costs, but suggested a materiality threshold before NRG could request compensation from IGPC for services rendered outside the ordinary course of business.

Position of NRG

NRG took the position that it had provided gas distribution services reliably and consistently to IGPC since July 2008 and that it had never denied service to IGPC.

Referring to the July 9th letter sent to IGPC, NRG submitted that the intent of the letter was to engage in a meaningful dialogue with the possibility of resolving some of the parties' outstanding issues and to gain a better understanding of IGPC's expansion plans[3]. NRG argued that if it was required to take any additional steps to providing service, then IGPC should be required to provide detailed information about its expansion plans. For example, it would require IGPC to provide its most recent quarterly and annual financial statements; to confirm whether its operational grants would be renewed and to provide a business plan for the expansion with project timelines, details of gas volumes and pressure and any preliminary engineering work done in the recent past.

[3] NRG Submission, Page 5, November 11, 2013

NRG stated that after not hearing back from IGPC, it inquired whether IGPC's expansion plans were put on hold, to which IGPC responded that it was in the "preliminary engineering stages". As a result, NRG assumed that IGPC was not proceeding with the expansion. NRG considers IGPC's application to the Board under Section 42 premature and the requested Order of the Board unnecessary.

With respect to the invoices it sent to IGPC, NRG took the position that since it had to seek the services of external consultants to do preliminary engineering work, it was entitled to charge IGPC for such work. NRG requested the Board reject IGPC's application with costs payable to NRG.

Position of Board Staff

Board staff took the position that NRG was a monopoly service provider and IGPC's only source of natural gas. Section 42(2) of the Act in its view provides clearly that "a gas distributor shall provide gas distribution services to any building along the line of any of the gas distributor's distribution pipe lines upon the request in writing of the owner, occupant or other person in charge of the building." The Gas Distribution Access Rule of the Board further states that "[A] gas distributor shall provide gas distribution services in a non-discriminatory manner".

Board staff submitted that NRG's conduct to date did not reveal a genuine interest in assisting IGPC in meeting its potential needs for additional gas service. NRG's letter of July 9th appeared to be a clear refusal to discuss IGPC's potential needs for additional gas service. In addition, NRG did not provide any explanation for the $7,000 amount invoiced to IGPC.

Board staff submitted that NRG's conduct borders on an abuse of monopoly power, and the Board should intervene to ensure that IGPC receives the gas service it requires. Board staff submitted that the Board should grant much of the relief sought by IGPC but disagreed with IGPC's suggestion of a materiality threshold for costs incurred in assessing the pipeline requirements. In Board staff's view, NRG should be able to absorb internal costs related to requests which would generally be considered routine utility business. However, in cases where NRG expects to incur significant costs related to engineering studies or consultants, Board staff suggested that NRG could request a deferral account in the next Incentive Regulatory Mechanism ("IRM") proceeding. Board staff also submitted that NRG should pay for IGPC's costs related to this aspect of the proceeding.

Position of The Town of Aylmer

The Town of Aylmer made a similar argument to Board staff and submitted that NRG was obligated to provide all services for which it holds a monopoly. The Town of Aylmer submitted that the refusal by NRG to meet and discuss the proposed expansion plan is akin to denial of service within Section 42(2) of the Act. In its view, NRG must provide the services requested by IGPC unconditionally.

The Town of Aylmer further suggested that the Board should order NRG to provide IGPC with all the required financial and technical information that is related to the provision of gas supply for the proposed plant expansion. In its view, NRG should not be allowed to recover the cost of this proceeding from ratepayers but rather, the shareholders should pay the legal costs.

NRG rejected the Town of Aylmer's argument that service should be provided unconditionally. NRG submitted that it needs to balance the interest of all ratepayers. IGPC had provided no indication to NRG of whether its operating grants would continue beyond 2016. NRG noted that based on the review of IGPC's financial statements, it believed that IGPC would not be able to survive without operating grants from the government.

Board Findings

The evidence does not support the allegation that NRG has failed to fulfill its obligations under section 42(2) and therefore the Board will not grant the Order sought by IGPC.

In making a determination whether service has been denied, the Board considered the evidence put before it in this proceeding. While IGPC has asked the Board to consider the years of difficulties between the parties, in making a finding, the Board must consider whether there is a denial of service in the current timeframe based on the evidence before it in this proceeding. On that basis, IGPC has failed to provide sufficient evidence supporting its position that service has been denied.

The Board notes that there is no evidence of any contact between IGPC and NRG during the time period from the July 9th letter and the July 24th letter. There is no evidence before the Board that between July 25, 2012 and the commencement of this proceeding in October 2012 IGPC communicated with NRG regarding what it considered to be a denial of service.

In response to Board Staff's interrogatory, IGPC confirmed that it had no further discussions in relation to its request to secure additional gas service after its letter of July 25, 2012. IGPC explained its decision to not take further steps on the basis that it did not want to incur costs from NRG levied as a result of inquiries regarding further supply, without having some control over the "nature and extent of such potential charges[4]." The Board notes that the first of the invoices issued by NRG was dated August 24, 2012, approximately one month after IGPC responded to NRG that it was in the preliminary design stage. Therefore there was a month during which IGPC had not been invoiced but did not pursue further discussions with NRG.

IGPC did not take the opportunity to meet with NRG when contacted through the July 24th letter. It seems reasonable that on the basis of the July 25th letter, NRG concluded that IGPC's expansion was not ready to proceed. Therefore the Board is left to consider the two week period between July 9th and the 25th and determine whether the failure of NRG to arrange a meeting during that time in the preliminary stage of the project constitutes a denial of service, and if so, whether any such denial of service persists to date.

The Board is of the view that a supplier should be responsive to the requests of its customers. The Board does not agree with the response provided by NRG in its letter of July 9th, since NRG appears to be seeking to impose pre-conditions on the provision of gas distribution services that are not contemplated by s 42(2). However, the Board is of the view that based on the limited overtures by IGPC to pursue a discussion on the proposed expansion, and on the basis that the expansion was only at the initial stages of planning, the actions of NRG do not constitute a denial of service.

As the Board has decided not to grant the Order, it will not consider whether the Order should be an enforceable provision as was suggested by IGPC and supported by Board Staff.

[4] IGPC response to Board staff second round of interrogatory # 2, October 28, 2013

Amount Invoiced Concerning Proposed Expansion of Service

NRG presented IGPC with invoices for unspecified services related to the expansion of service. The Board does not understand how NRG incurred approximately $7,000 of costs prior to meeting with IGPC to discuss the proposed expansion.

A supplier is entitled to charge customers for expenses which exceed the regular costs of conducting business, if approved by the Board and included in a Rate Order. IGPC does not dispute this position[5]. The Board is not persuaded that these expenses, which appear to be incurred in the regular course of functioning as a gas distributor, should be paid by IGPC. NRG should be able to absorb the routine costs of doing business as part of its operating expenses. While the Board has not been asked to make a ruling on the invoiced costs, the Board advises parties that the matter in which expansion costs are dealt with should not act as a barrier to parties engaging in discussions regarding an expansion of service.

Conclusion

For the reasons outlined above, the Board is of the view that IGPC has not established that an Order requiring NRG to provide service is necessary at this time.

The Board notes that it should be self-evident to NRG, as an entity regulated by the Board, that it is required to operate in accordance with the terms of the Act.

Issue 2: With respect to the cost items listed below, what is the appropriate amount to be included in determining the capital cost of the IGPC pipeline?

> ***2.1.1 Legal costs***
> ***2.1.2 Contingency costs***
> ***2.1.3 NRG staff costs (Mr. Bristoll)***
> ***2.1.4 Interest during construction***
> ***2.1.5 Insurance costs and other service costs (e.g. auditing)***
> ***2.1.6 Administrative penalty; and***
> ***2.1.7 Costs arising from this proceeding***

[5] IGPC Argument-in-Chief, Page 11, November 4, 2013

The PCRA provided for a pre-construction capital contribution of $3.5 million by IGPC, based on the forecasted cost of the pipeline. The PCRA also included provisions whereby the capital contribution would be adjusted as necessary after the actual, costs of the pipeline were known.

Before dealing with each of these specific capital cost items this Decision will deal with the preliminary matter of the Board's jurisdiction.

Preliminary Matter: Jurisdiction of the Board Regarding Determination of Capital Contribution

NRG submitted that the Board had already determined the capital costs of the pipeline for the purposes of rates in EB-2010-0018 and those findings were final and binding on IGPC. NRG further submitted that if the Board was going to take jurisdiction over private contractual disputes, then the Board must be governed solely by the law of the contract. NRG argued that the issue is one of contractual interpretation, and that this is not a rate-making exercise. The only jurisdiction the Board has, in its view, is to interpret the words of the PCRA and apply them to the issues in dispute.

IGPC disagreed with NRG's submission that the matter before the Board is simply a contractual dispute for which the Board was taking jurisdiction. IGPC submitted that the Board's Decision on the Motion to Review EB-2012-0396 (described in Appendix A of this Decision) clearly determined that the capital contribution was a rate within the meaning of the Act. IGPC further submitted that NRG did not appeal the Board's Decision (EB-2012-0396) and also did not request a review. IGPC submitted that to once more argue that the issue is a contractual dispute is akin to challenging the Board's decision in EB 2012-0396.

Board Findings

The Board does not accept NRG's characterization of the exercise of the Board's jurisdiction in this proceeding as being a purely contractual interpretation. Although EB-2010-0018 determined capital costs of the pipeline that would be included in rate base and form part of distribution rates, EB-2010-0018 did not set the amount of the capital contribution as contemplated in the PCRA. In other words, the Board's rates proceeding did not determine the issues in this proceeding concerning the capital costs of the pipeline.

The Board has already determined in EB-2012-0396, for the reasons set out in that decision, that a capital contribution is a “rate” within the meaning of the Act. The Board is directed by section 36(2) of the Act to ensure that all rates charged by a utility to a customer are just and reasonable, and section 36(1) of the Act specifically provides that the Board “is not bound by the terms of any contract”. In setting just and reasonable rates, the Board can adopt whatever method or technique that it considers appropriate. Accordingly, contrary to NRG’s argument, determining the appropriate amount of IGPC’s capital contribution falls within the Board’s jurisdiction under the Act to set rates. The same logic holds with respect to the costs IGPC incurs for the letter of credit.

The Board considers that the most appropriate method to determine the proper amount of IGPC’s capital contribution is with reference to the PCRA. The PCRA was negotiated between NRG and IGPC and filed in the original leave to construct proceeding (EB-2006-0243). It represents their agreement as to how the capital contribution would be determined. Although the Board did not formally approve the PCRA, it was referenced by the Board in the leave to construct proceeding, and provided part of the context to that decision. In that Decision, the Board stated:

> The Board is satisfied that the terms and conditions of the two agreements, the GDC (Gas Delivery Contract) and the PCRA, adequately protect the interests of NRG and its ratepayers against anticipated risks. In making its finding to grant the requested leave to construct, the Board is placing significant reliance on the terms and conditions of both the PCRA and GDC that protect the interest of NRG’s ratepayers.[6]

The Board notes that the PCRA is similar to many contracts that the Board has taken notice of in other leave to construct applications.

The Board wishes to emphasize that although it will apply the provisions of the PCRA in setting the appropriate amount of the capital contribution, it will do so in exercising its jurisdiction to set rates. The Board is not taking jurisdiction over a contractual dispute issue. As indicated in EB-2012-0396 the Board is not bound by the PCRA and could adopt a different method to set the capital contribution in setting just and reasonable rates.

[6] Decision and Order EB-2006-0243, page 4, February 2, 2007

2.1.1 Legal Costs

NRG has claimed a total of $638,226 as IGPC's contribution to NRG's legal costs included in the capital cost of the pipeline. IGPC is willing to accept $382,272 as the appropriate amount to be paid and therefore seeks a refund of $255,954.[7]
Section 3.14 of the PCRA states the following concerning legal costs:

> ....In determining reasonable costs attributable to the Capital Cost, the following considerations will be taken into account:
>
> (a) Legal costs will include the reasonable legal costs of [NRG] to establish gas distribution service for [IGPC], including the reasonable legal cost to prepare and obtain the Leave to Construct from the OEB; acquire any temporary or permanent land rights required to complete the Pipeline Work; review any procurement or tendering documentation, and draft and negotiate this Agreement and any other documentation required to provide gas distribution service to [IGPC]

Board Findings

Taking the provisions of the PCRA into consideration, the Board finds that the legal costs that should be included in IGPC's capital contribution are essentially the legal costs reasonably paid by NRG in order to construct the pipeline and to put in place its pipeline construction and gas distribution arrangements with IGPC. The Board does not consider that the legal costs should encompass costs concerning disputes between NRG and IGPC about fulfillment of their obligations under these arrangements.

A large part of the legal costs claimed by NRG are for two motions before the Board in which NRG and IGPC disputed issues concerning fulfillment of their respective obligations. The first of these motions was an emergency motion filed in 2007 in which IGPC alleged that NRG had inappropriately failed to sign the Assignment Agreement and Bundled T-Service Agreement that the parties had negotiated (the "Emergency Motion"). The second of these was a motion filed in 2008 in which IGPC alleged that the amount of the letter of credit required by NRG exceeded the amount required under the PCRA (the "Letter of Credit Motion"). In those motions NRG also raised issues

[7] Appendix A, NRG Reply Submission.

concerning the conduct of IGPC. The legal costs claimed by NRG were $94,800 for the Emergency Motion and $82,554 for the Letter of Credit Motion.

In the Board's view these two motions essentially concern disputes between NRG and IGPC rather than costs to construct the pipeline or put construction or gas distribution arrangements in place. Accordingly, the Board does not consider that the legal costs of these motions should be included in the legal costs to be paid by IGPC as part of its capital contribution. The Board notes that although it made no cost order for either motion, in the Emergency Motion both parties made submissions on costs and there was no suggestion in those submissions that NRG's costs should be part of IGPC's capital contribution. Had the Board deemed it appropriate for one party to pay the other's costs, it would have done so in the context of the cost awards process in the individual hearings.

NRG also included certain legal costs as contingency costs (see section below). For the reasons cited above, the Board will not permit NRG to recover any legal costs that were included as contingency from IGPC, that relate to any other proceedings between the parties before the Board.

NRG's claim for legal costs also includes an account of Lenczner Slaght dated September 22, 2010 for $197,643[8]. IGPC submitted that this account should be excluded from its capital contribution because it is for the Board proceeding in which NRG sought rates approval from the Board (EB-2010-0018). NRG did not dispute IGPC's position on this account. The Board agrees that the amount of this account should be excluded from IGPC's capital contribution. This account would reasonably be considered to relate to either the parties' dispute concerning IGPC's capital contribution or more general issues concerning NRG's rates.

IGPC also initially disputed legal costs it believed were related to shareholder advice ($26,426) and project management ($15,000). In its response to interrogatories, NRG indicated that it was not aware of any shareholder advice being claimed in its legal costs.

Concerning the costs that IGPC categorized as project management, NRG submitted that since IGPC's counsel was extensively involved in every stage of the project, IGPC should not dispute NRG's resulting legal costs. In its argument in chief, IGPC did not

[8] Appendix A, NRG Reply Submission, November 14, 2013

pursue its arguments concerning these aspects of NRG's legal costs. The Board accepts NRG's arguments on these issues and considers that these legal costs should be included in IGPC's capital contribution.

2.1.2 Contingency Costs

As a result of the motions that were filed during the leave to construct proceeding, NRG in its evidence indicated that it expected a litigious relationship with IGPC and wanted some protection against unanticipated legal fees[9]. Board staff essentially agreed with NRG's position on this issue.
Board staff noted that NRG should be allowed to recover contingency costs as they had already been incurred[10].

IGPC in its submission referred to the evidence of NRG in the rates proceeding (EB-2010-0018) confirming that NRG had no plans for the contingency costs[11] two years after the pipeline came into service. IGPC submitted that it had received no explanation from NRG as to why legal fees were required and how they related to the construction of the IGPC pipeline after it was completed.

IGPC submitted that it appeared that NRG was attempting to recover costs related to the motion that considered whether the Board had jurisdiction to consider the disputed costs of the pipeline. IGPC also claimed that the contingency costs were attempting to recover costs related to the current proceeding. IGPC submitted that NRG should not be allowed to recover costs that are not related to the construction of the IGPC pipeline but which are a result of NRG's refusal to undertake a reconciliation of the actual costs of the pipeline. Accordingly, IGPC submitted that the full amount of contingency costs including the return should be refunded to IGPC.

NRG disputed IGPC's argument that there should be no contingency costs after the pipeline was built. NRG noted that it had been five years since the IGPC pipeline came into service and NRG was still incurring significant costs, both external and internal. The issue of the capital costs was still outstanding and without the IGPC pipeline, NRG argued that none of these costs would have occurred. NRG submitted that the utility must remain whole and if NRG is unable to recover the costs, then the other ratepayers of NRG would be subsidizing IGPC's capital costs. NRG submitted that it had already

[9] Transcript, Motion Hearing, Page 45, July 29, 2013
[10] NRG Evidence, Page 20, June 3, 2013
[11] Transcript, Technical Conference, EB-2010-0018, June 14, 2010, page 27

exceeded the contingency costs and there was no way for NRG to recover the additional costs.

NRG in its reply submission supported the position of Board staff that it was reasonable for NRG to make provision for contingencies on the basis that the relationship was litigious. NRG also dismissed IGPC's position that the contingency costs should be disallowed as they were not incurred until after the completion of the IGPC pipeline. NRG noted that the meaning of contingency is an event that could possibly occur in the future. NRG submitted that the contingency costs have been incurred and NRG's approach of including contingency costs was prudent and necessary to protect NRG's other ratepayers.

NRG submitted that the current proceeding and all other proceedings with IGPC were directly related to and caused as a result of the construction of the IGPC pipeline. The legal fees that IGPC objects to as contingency costs were according to NRG incurred as a result of IGPC's overly litigious strategy and adversarial tactics[12]. NRG submitted that IGPC should bear the contingency costs as it was directly responsible for those costs.

Board Findings

The PCRA in Section 3.6 states that "the contingency amount to be included in the Revised Estimated Capital Cost shall be limited to a maximum of ten percent of the Construction Agreement cost." There is no further elaboration as to what constitutes contingency cost.

IGPC has argued that the contingency costs should be disallowed simply because they occurred after the construction was completed. However, the PCRA does not state this and neither does it state that the contingency costs solely refer to construction contingencies.

The Board notes, however, that under the PCRA, contingency costs are part of the Revised Estimated Capital Cost but are not part of the Actual Capital Cost, which is what determines the ultimate amount of IGPC's capital contribution. Accordingly, in this proceeding it is not necessary for the Board to determine whether the contingency costs included in the Revised Estimated Capital Cost were appropriate; it is to determine whether the costs that were actually incurred, including those that were included in contingency costs, should be paid by IGPC.

[12] NRG Reply Submission, November 14, 2013, Page 27

Accordingly, the Board will not consider contingency costs as a separate item. To the extent that the contingency costs have actually been incurred, they should be included in other cost categories of the pipeline construction and will be considered by the Board as part of each cost category. A part of the claimed contingency, for example, related to certain legal costs. The Board has made its determination on those costs in the "legal costs" section above.

2.1.3 NRG Staff Costs

Board staff submitted that NRG should be disallowed from recovering the entire salary of Mr. Bristoll, President of NRG at the time, for 2006-2008 amounting to $385,045, from IGPC. Board staff noted that NRG had recovered the entire salary of Mr. Bristoll in 2007 and 2008 through rates and there was no evidence of capitalization of wages by NRG related to the IGPC pipeline in their cost of service application (EB-2010-0018) evidence. For the year 2006, a portion of Mr. Bristoll's salary was allocated to a related company. However, the hours allocated to NRG far exceeded the time spent by Mr. Bristoll on IGPC related activities in 2006. Consequently, the entire time spent by Mr. Bristoll on IGPC in 2006 was recovered in distribution rates. Accordingly, Board staff submitted that the salary of Mr. Bristoll for the years 2006 to 2008 had been recovered through rates and any additional recovery would be double-counting.

IGPC in its submission echoed the views of Board staff but revised the amount of Mr. Bristoll's salary to $394,405 which, as per the detailed pipeline cost schedule, includes an additional $9,360 allocated to Ayerswood Development[13].

IGPC also referenced an undertaking response[14] that shows an additional payment of $130,006 to Mr. Bristoll as consulting fees. IGPC submitted that NRG had refused to provide clarity on whether the capital costs include an additional $130,006 paid to Mr. Bristoll. NRG in an interrogatory response[15] indicated that the amount was an error and the interest expense related to the item in the schedule should be removed. IGPC submitted that NRG had not provided evidence to support that the $130,006 had been removed from the capital costs.

[13] Cost of Pipeline – Detailed Schedule, NRG response to IGPC IR#5 (Mark Bristoll - $385,045 + Ayerswood Development - $9,360)
[14] Undertaking Response J1.5, EB-2010-0018
[15] NRG Interrogatory Response IGPC #2, Q.17, October 28, 2013

IGPC submitted that NRG failed to provide any reasons for why Mr. Bristoll's time spent on IGPC was not part of his expected job duties. IGPC also reiterated the fact that NRG recovered Mr. Bristoll's salary in rates and then added the same amount to rate base.

NRG in its submission stated that Mr. Bristoll devoted nearly 100% of his time to the IGPC pipeline project prior to and during construction. NRG submitted that Mr. Bristoll's accounting and construction expertise was a key reason for the IGPC pipeline being built under budget and on time. NRG further noted that Mr. Graat, the new president of NRG, worked as many hours as Mr. Bristoll without any compensation and IGPC benefitted substantially from the involvement of Mr. Bristoll and Mr. Graat. NRG submitted that it had charged an appropriate rate to IGPC for Mr. Bristoll's services and had benchmarked the rate to that of a senior Chartered Accountant within the London area.

NRG argued that utilities routinely bill for project management work similar to that undertaken by Mr. Bristoll and NRG's Schedule of Service Charges allows for contract work to be done for customers. NRG submitted that it was simply unreasonable for IGPC to believe that it would bear none of NRG's internal costs.

Board Findings

Mr. Bristoll was a full-time employee of NRG in 2007 and 2008 and a part time employee in 2006. It is not uncommon for a senior employee in a small company to devote a considerable portion of his/her time to accommodate a large customer. Furthermore, there is no evidence that NRG had to incur additional costs such as overtime or additional employee costs due to the unavailability of Mr. Bristoll for other NRG work.

There is no dispute that NRG recovered the salary of the president through its distribution rates in 2006, 2007 and 2008. The Board does not agree with NRG's argument that it has the flexibility to allocate part of Mr. Bristoll's normal salary costs to IGPC. NRG has already recovered the entire salary in rates and cannot recover the same amount from IGPC through a notional re-allocation. If NRG wished to try to recover a portion of Mr. Bristoll's salary from IGPC, it should have removed the specific amount from its Operations Maintenance & Administration ("OM&A") included in distribution rates for the respective years. NRG would then be able to include the specific portion in the capital cost of the pipeline and appropriately capitalize the expense. However, NRG recovered the entire salary in rates and at the same time allocated a portion of the same salary to the capital cost of the pipeline. This is contrary to ratemaking principles and would amount to double recovery. Accordingly, the Board will disallow the entire amount of $385,045 from inclusion in the capital contribution.

2.1.4 Interest During Construction

(a) Aid-to-Construct Payments

Section 3.3 of the PCRA provides for three types of aid-to construct payments to be paid by IGPC. The issues between IGPC and NRG concern the payments under section 3.3(b). The relevant parts of section 3.3 read as follows:

> 3.3 [IGPC] shall make payments toward the Initial Estimated Aid-to-Construct, as follows:
>
> (b) Prior to the award of the Construction Agreement, the amount of the monthly invoices provided by [NRG] for reasonable internal, consulting and third party expenses incurred in the prior calendar month within fifteen (15) Business Days of receiving such invoice;

The evidence includes a listing of the invoices NRG issued to IGPC for these payments, the dates IGPC paid these invoices, the expenses covered by the NRG invoices and the interest that NRG charged IGPC for late payment of its invoices.

IGPC has raised 3 issues concerning these aid-to-construct payments:

1. NRG charged interest for late payment after 15 calendar days, rather than 15 business days, had elapsed;

2. Some of the expenses covered by NRG's invoices to IPGC were excessive, because they included late payment charges by NRG's suppliers that were NRG's fault; and

3. A charge for $7099 relating to consulting work by Mr. Bristoll should not have been included.

Concerning issue 1, the evidence indicates clearly that NRG calculated interest on the basis of calendar days rather than business days. This is contrary to the PCRA which stipulates business days in section 3.3(b). However, IGPC is not seeking this relief and noted in its submission[16] that the amounts claimed are very small and not worth contesting. Accordingly, the Board will not require NRG to recalculate this aspect of the interest correctly.

Concerning issue 2, NRG does not appear to dispute IGPC's position that late payment charges caused by NRG are included in NRG's invoices to IGPC. The Board considers that such charges are not "reasonable...third party expenses" as contemplated by section 3.3(b) of the PCRA, and accordingly agrees with the principle that such expenses should be excluded from IGPC's payments. However, neither party has provided evidence to substantiate the amount involved. Accordingly, the Board does not require any deduction of these late payment charges from the aid-to-construct payments.

Concerning issue 3, NRG agrees with IGPC that the charge for $7099 referred to in issue 3 was included in the interest charges in error. Accordingly, the Board agrees that it should be removed.

(b)Interest During Construction

The relevant parts of section 3.14 of the PCRA provide as follows:

> 3.14 ....In determining reasonable costs attributable to the Capital Cost, the following considerations will be taken into account:
>
> ....
>
> (d) Utility costs shall include the reasonable cost of interest during construction calculated in accordance with the OEB approved methodology....

IGPC submits that NRG has made 3 errors in charging interest during construction. In IGPC's view:

(i) NRG has applied the wrong interest rate;
(ii) NRG has charged interest for the wrong period; and
(iii) NRG has compounded interest charges but should not have done so.

[16] IGPC Submission, Page 27, November 7, 2013

IGPC submits that because of section 3.14 (d), the Board should apply the approved OEB rates for interest during construction. NRG submitted that the Board should not apply the approved OEB rates, because section 3.14 requires only that the OEB rates be “taken into account” and the interest rate applied by NRG is a commercially reasonable rate.

The Board notes that the only applicable “OEB approved methodology” consists of the approved OEB interest rates for calculating interest during construction. These are set out in the Board’s Prescribed Interest Rates for construction work in progress posted on the OEB website[17]. For the period in question, the approved OEB interest rates were 5.18% for the first and second quarter of 2008 and 5.43% for the third and fourth quarter of 2008. The Board considers it appropriate to apply the approved OEB interest rates in this instance.

NRG has charged interest from the date the last aid-to-construct payment was due to the date NRG received the last invoice from its primary contractor. NRG submitted that this period is appropriate because it reflects the period during which NRG was required to finance the pipeline project. IGPC submitted that NRG should have ceased to charge interest at the point when the capital costs of the pipeline were included in NRG’s rate base, because in its view to charge interest beyond that point would be double counting.

The Board agrees with NRG that the appropriate period to charge interest is the period during which NRG was financing the project costs. The Board does not agree that charging interest after the capital costs were included in NRG’s rate base would cause double counting. This interest was to be paid as part of the capital contribution costs and was separate from the amount that was added to rate base.

However, the Board does not consider that the period applied by NRG is the most appropriate period to achieve this purpose. The Board considers that to best reflect the financing period, interest during construction should have been charged from the date NRG’s first invoice from its primary contractor was due to the date NRG’s last invoice from its primary contractor was due.

The Board orders NRG to make the adjustments outlined above.

[17] http://www.ontarioenergyboard.ca/OEB/Industry/Rules+and+Requirements/Rules,Codes and Guidelines/Prescribed Interest Rates

2.1.5 Insurance Costs and Other Service Costs

NRG charged IGPC $62,000 for insurance for coverage during development and construction of the pipeline. In response to an interrogatory[18], NRG confirmed that it did not incur additional costs to insure the pipeline; the pipeline was simply included in NRG's overall insurance costs that NRG recovered through rates.

Board staff argued that the inclusion of $62,000 to the contributed capital of the pipeline amounts to double recovery as this amount has already been recovered through rates. IGPC made a similar argument.

NRG argued that IGPC had benefitted from NRG's insurance coverage and it was therefore appropriate for IGPC to pay for a portion of NRG's insurance. NRG also submitted that the Board does not dictate how to manage costs within the utility's revenue requirement envelope. NRG submitted that the insurance costs should be accepted as there was no evidence that the cost of insurance incurred by NRG was not reasonable or prudent[19].

IGPC also disagreed with NRG's costs of $7,639 related to its auditor. IGPC submitted that there was no need for an auditor and that these costs were related to providing shareholder advice. NRG in reply stated that it had never sought costs from IGPC for the benefit of its shareholder.

Board Findings

The issue before the Board is whether incremental insurance costs have been incurred for the construction of the pipeline. There is no evidence that NRG incurred incremental insurance costs. NRG was able to add insurance coverage during the construction phase to its existing policy without incurring any costs. NRG's argument is twofold; one is that since IGPC received insurance coverage, it should pay for it and secondly the global OM&A envelope approved by the Board in the context of EB-2010-0018 allows NRG the flexibility to allocate costs as it sees fit.

The Board's decision is guided by ratemaking principles for just and reasonable rates, one of which is that there should be no recovery for costs that have not been incurred. NRG did not incur incremental insurance costs for the pipeline. Although utilities in

[18] Response to IGPC Interrogatory #14, June 28, 2013
[19] NRG Reply Submission, November 14, 2013, Page 35

managing their operations have certain flexibility to allocate OM&A expenses within the envelope amount approved by the Board, this does not mean that NRG can allocate part of its insurance costs to IGPC to charge for insurance in the current context. If NRG wanted to seek to charge insurance costs to IGPC, then it should have capitalized the costs and noted this in the cost of service proceeding before the Board (EB-2010-0018). NRG did not do so and has been fully compensated for its insurance costs in rates. Accordingly, the Board will disallow the $62,000 in insurance costs.

The Board will not adjust the auditor costs as initially requested by IGPC. The Board accepts NRG's statement that audit costs were not for the benefit of the shareholder but rather related to the construction of the pipeline. The costs appear reasonable to the Board.

2.1.6 Administrative Penalty

In EB 2006-0243, the Board ordered that NRG pay an administrative penalty of $140,000. Later, in EB-2010-0374 the Board vacated the administrative penalty[20]. NRG has confirmed that did not pay the administrative penalty and has not included it in the costs claimed from IGPC. [21] IGPC is satisfied that the administrative penalty has been excluded and accordingly this item is no longer a disputed issue in this proceeding.

2.1.7 Costs Arising from this Proceeding

NRG and IGPC are seeking to recover the costs of this proceeding from each other. Board staff submitted that it was not clear whether NRG or IGPC was at fault for not resolving the disputes between them. Accordingly, Board staff submitted that there should be no costs awarded in this proceeding. However, Board staff in its submission recommended that NRG should pay the legal costs of IGPC related to the Section 42 issue as in its view NRG's conduct bordered on an abuse of its monopoly power.

Board Findings

The Board agrees with the submission of Board staff that it is unclear who was at fault for the disputes between NRG and IGPC. The Board is disappointed that what would seemingly be routine matters to be settled by negotiation between the parties have been brought before the Board. The Board is of the view that NRG and IGPC have had

[20] Board Decision EB-2010-0374, February 11, 2011
[21] Response to interrogatory #5, EB-2010-0018, January 17, 2011

mixed success in this proceeding. For these reasons, the Board will not award costs arising from this proceeding. With respect to the Board's own costs for these two proceedings, the Board orders that these should be split evenly between NRG and IGPC.

Issue 3: Are the capital contribution amounts and the financial assurance provided to NRG by IGPC for the existing NRG facilities serving IGPC reasonable?

IGPC submitted that once the Board determines the actual capital costs of the IGPC pipeline, the analysis can move to determining the proper amount of IGPC's capital contribution.

IGPC presented two calculations, one based on NRG's claimed costs ($175,836 reimbursement to IGPC) and one based on IGPC's claimed costs ($981,708 reimbursement to IGPC).

NRG is currently holding a Letter of Credit for $5.2 million provided by IGPC. The amount has remained unchanged since its issuance in April 2008[22]. IGPC submitted that as per the terms of the PCRA, NRG was required to reduce the amount of the letter of credit to reflect the net book value of the IGPC pipeline in NRG's rate base. IGPC submitted that NRG had refused to reduce the value of the letter of credit and this had increased the cost for IGPC to maintain the letter of credit to the original amount. IGPC estimated the incremental cost to fully fund the letter of credit for 5 years at the original amount, rather than reducing the amount as specified in the PCRA, at over $150,000.

IGPC submitted that the letter of credit should be immediately reduced to $3,491,731 reflecting the net book value of the IGPC pipeline according to NRG's rate base for fiscal 2014. IGPC submitted that the Board should order an exchange of the letter of credit to occur within 30 days of the Board's Decision and Order in this proceeding. IGPC further requested that the Board order that the letter of credit be reduced annually on or before November 1 in each year by the amount of depreciation.

Board staff agreed that once the Board makes a determination on the capital cost of the pipeline, NRG should adjust the Letter of Credit based upon the net book value of the pipeline in NRG's rate base as per section 7.6 of the PCRA.

[22] Response to Board staff IR# 6c, June 28, 2013

NRG in its reply agreed with Board staff that the letter of credit should be adjusted once the Board determines the capital cost of the pipeline. NRG also agreed with the starting point used by IGPC to recalculate the capital contribution. NRG made no comment about the incremental cost to IGPC of the letter of credit not being reduced.

Board Findings

All parties agree that the letter of credit should be adjusted. However, the Board disagrees with NRG's view that adjusting the letter of credit is dependent upon determining the capital cost of the pipeline. Section 7.6 of the PCRA states that the amount of the letter of credit should be the net book value of the facilities allocated to IGPC, as determined by NRG in accordance with OEB-approved methodology. Net book value was determined by the Board in EB-2011-0210 as part of the rate base amount and therefore there was no reason for NRG to refuse to adjust the letter of credit on an annual basis in accordance with section 7.6 of the PCRA[23].

The Board orders NRG to immediately take the necessary steps to enable IGPC to adjust the letter of credit for NRG's fiscal 2014 rate year to reflect the net book value of the IGPC pipeline as of October 1, 2013. The net book value in 2014 as per NRG's evidence in EB-2010-0018 is $3,491,731[24]. NRG is to take all necessary steps to enable IGPC to make this adjustment within 30 days of the Board's Decision and Order in this proceeding. The Board further directs NRG to take all necessary steps to enable IGPC to adjust the letter of credit on an annual basis corresponding to the commencement of deliveries under the Gas Delivery Agreement as per section 7.6 of the PCRA.

IGPC in its submission has noted the cost of maintaining an unadjusted letter of credit for the past five years. IGPC has estimated the cost to be in excess of $150,000. No substantiating evidence was provided concerning the estimate of $150,000, but neither did NRG dispute it. There is no doubt that IGPC has had to bear additional costs because of NRG's refusal to enable revision of the letter of credit on an annual basis which was in clear contravention of section 7.6 of the PCRA. The Board believes that IGPC should not bear the cost of the excess amount. Accordingly, the Board orders NRG to refund $150,000 to IGPC.

[23] Section 7.6 agrees to reduce the amount of the Delivery Letter of Credit equal to the net book value of the Utility Connection Facilities allocated to the customer at the time.
[24] EB-2010-0018, Exhibit I, Tab 7, Page 6, Interrogatory #3, August 31, 2011

Issue 4: What, if any, is the appropriate amount of payment including any interest owed by NRG to IGPC?

Board staff noted that NRG has confirmed that it has been paid the total amount in dispute[25]. Board staff submitted that based on its arguments, NRG owes $652,503 as a refund to IGPC.

IGPC in its submission submitted that it is owed $981,708 and reconciliation should have occurred in 2009. Using a rate of Prime plus 1% as referred to in s. 3.8 of the PCRA, IGPC has included a 4% interest rate from 2009 to 2013 and has submitted a total amount of $1,194,397.89 that it is owed.

NRG in its submission submitted that the above issue was dependent upon the resolution of the capital cost of the IGPC pipeline.

Board Findings

The Board has made certain findings in this Decision that impact the total cost of the pipeline. The table below provides the Board's Decision on the disputed costs:

Cost Item	Disallowed Costs as per Board's Decision
Legal Costs	Revised total to be provided by NRG
NRG Staff Costs	$385,045
Interest	NRG to provide revised table
Insurance Costs	$62,000

IGPC in its submission has argued for an interest payment of $212,690 representing the cost of the overpayment from 2009 to 2013. IGPC has submitted that the reconciliation to determine actual capital cost of the pipeline should have occurred by January 1, 2009. In other words, IGPC is owed interest on the overpayment for five years which has been calculated at the rate of Prime + 1.00% in accordance with section 3.8 of the PCRA.

The pipeline was added to rate base in August 2008. IGPC has submitted that reconciliation to actual costs should have occurred within five months. The Board is of

[25] Response by NRG to Board staff interrogatory #1, October 28, 2013

the view that reconciliation should have occurred by the end of 2008. The PCRA states that NRG was to provide IGPC with the actual costs of the pipeline within 45 days of the pipeline entering service, or on a timeframe agreed to by the parties. If there was a disagreement, the PCRA provides that the parties were to negotiate in good faith for 20 business days, after which the matter could be referred to the Board for resolution. As the pipeline entered service in August 2008, the disagreement should have been referred to the Board before the end of 2008. Even providing for a very generous hearing schedule, the matter could have been resolved sometime in calendar 2009. Accordingly, the Board orders that NRG is liable to pay interest for 4 years (2010- 2013) for the excess amount as determined in this Decision. NRG is further ordered to calculate interest on the amount refunded by NRG to IGPC, at the rate of Prime + 1.00%, as contemplated by s 3.8 of the PCRA. The Prime Rate to be used shall be calculated on the basis of the rate existing for each of the years included in the calculation.

In addition, NRG is required to pay a further $150,000 to IGPC representing the cost of maintaining an unadjusted letter of credit for five years.

Issue 5: If any amounts are owing from NRG to IGPC, by what means and in accordance with what terms should IGPC be reimbursed?

In its submission, Board staff submitted that the refund amount owed to IGPC may be too large for NRG to refund as a single payment. A suitable alternative in its view would be to refund the amount over a three year period through a rate rider. Board staff submitted that a deferral account should be established that applies Board prescribed interest rates. IGPC in its submission made a similar observation that the refund amount of $1,194,397.80 that IGPC claimed is fairly significant and NRG should be directed to refund the amount over an 18 month period through a rate rider.

IGPC also submitted that the rate base had been overstated since the Board’s Decision in EB-2010-0018. IGPC sought direction from the Board as to the manner in which the overpayment should be corrected.

NRG in its submission agreed with Board staff regarding the establishment of a deferral account to capture amounts owing to IGPC.

Board Findings

The Board agrees with Board staff and IGPC that the refund amount resulting from the Board's Decision is likely to be fairly significant for a small utility such as NRG. The Board orders NRG to establish a deferral account for this purpose (IGPC Pipeline Refund Deferral Account), the amount of which will be determined once the Board has determined the revised capital contribution. The Board orders NRG to clear the deferral account through a rate rider ending September 30, 2016.

IGPC has also sought an adjustment to the rate base. The Board's rates were declared final in NRG's last cost of service proceeding (EB-2010-0018) and the Board at that time was aware of the dispute between NRG and IGPC regarding the capital cost of the pipeline. The Board also issued subsequent rate orders in 2012 and 2013 that were final. Consequently, the Board will not make an adjustment to the rate base.

THE BOARD ORDERS THAT:

1. The Board orders NRG to file and serve on IGPC, within 21 days of the date of this decision a table reflecting the Board's findings in this Decision concerning all amounts to be paid by NRG to IGPC, including interest, together with all supporting calculations

2. IGPC and Board staff will have 14 days after the receipt of NRG's calculations to file with the Board and serve on the parties any comments on the accuracy of these NRG's figures and calculations.

3. NRG will have 7 days after receiving any such comments to file with the Board and serve on IGPC any response to the comments.

DATED at Toronto, February 27, 2014

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

History of the Capital Contribution Proceeding

IGPC brought the capital contribution dispute before the Board in NRG's 2011 rates proceeding (EB-2010-0018). In that proceeding, the Board determined that it would only address matters that impact NRG's rate base and that issues relating to the PCRA were outside its jurisdiction. The Board determined that the capital contribution dispute was essentially a contractual dispute related to the Pipeline Cost Recovery Agreement ("PCRA") signed by the two parties.

Subsequently the Board, on its own motion, reviewed its decision in EB-2010-0018 concerning jurisdiction over capital contribution issues (EB-2012-0396). On October 4, 2012, the Board determined that its original decision on this issue had been incorrect. It determined that a capital contribution is a "rate" within the meaning of the Act and that the Board therefore had jurisdiction to determine the appropriate figure for all amounts paid by IGPC to NRG.

The Board further issued a Notice of Application on April 2, 2013, pursuant to the Board's Decision in EB-2012-0396 advising parties that the Board had initiated a new proceeding (Board file No. EB-2013-0081), to review the capital contributions paid by IGPC to NRG.

Procedural Steps related to this proceeding

In Procedural Order No. 2 issued on May 17, 2013, the Board determined a final Issues List and provided dates for filing interrogatories and responses to interrogatories.

IGPC and Board staff submitted interrogatories to NRG. On July 12, 2013, IGPC filed a motion pursuant to Rule 29 of the Board's Rules of Practice and Procedure requiring NRG to provide full and adequate responses to specific interrogatories filed by IGPC. IGPC further requested that the motion be heard orally. On July 29, 2013, the Board held an oral hearing concerning IGPC's motion to require NRG to respond to certain interrogatories.

In its Decision and Procedural Order No. 4 issued on August 29, 2013, the Board directed NRG to respond fully to certain interrogatories and also ordered a settlement conference to be held on September 18, 2013 with the objective of reaching a settlement on the issues before the Board. However, no settlement was reached between the parties.

In Procedural Order No. 5 issued on October 11, 2013, the Board made provision for a second round of interrogatories for both, IGPC and NRG. The Board further made provision for IGPC to file its argument-in-chief for the Section 42 issue and the parties to file submissions followed by IGPC to file a reply.

With respect to the other issues (Issues 2 to 5) dealing with the capital cost of the pipeline, the Board made provision for filing submissions and then reply to the submissions from NRG and IGPC.

The Town of Aylmer filed a submission on the Section 42 issue. Since the Board did not make provision for the Town to make submissions in its Procedural Order, NRG filed a letter on November 13, 2013 objecting to the Town's submission and indicated that if the Board were to accept the submission, then NRG should have an opportunity to respond.

The Town of Aylmer in a letter dated November 18, 2013 noted that it was accepted as an intervenor and it had participated throughout the proceeding. However, the Town did not object to the request of NRG to file a reply to any issues that were raised only by the Town. The Board in Procedural Order No. 6 accepted the submission of the Town but granted NRG an opportunity to respond if it wished to do so.

EB-2014-0206

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

AND IN THE MATTER OF an Application by Natural Resource Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act, 1998,* for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission, and storage of gas as of October 1, 2014; and

AND IN THE MATTER OF the quarterly rate adjustment mechanism.

BEFORE: Ken Quesnelle
Presiding Member and Vice Chair

Marika Hare
Member

DECISION AND INTERIM RATE ORDER

September 25, 2014

Natural Resource Gas Limited (“NRG”) filed an application dated September 12, 2014, with the Ontario Energy Board (the “Board”) for an order or orders approving or fixing just and reasonable rates and other charges for the sale and distribution of natural gas commencing October 1, 2014 (the “Application”).

The Application was made pursuant to section 36(1) of the Act and in accordance with the Quarterly Rate Adjustment Mechanism established by the Board for dealing with changes in gas costs involving all rate regulated gas distributors (EB-2008-0106).

NRG provided written evidence in support of the proposed changes outlined in the Application. The Application and pre-filed evidence was provided by NRG to all parties of record in NRG's last cost of service proceeding, EB-2010-0018.

Parties wishing to comment on the Application were required to file their submissions with the Board by September 17, 2014. No comments were received from any party.

In NRG's April 2014 QRAM Application (EB-2014-0053), NRG, a customer of Union Gas Limited ("Union"), indicated that it was unable to purchase the required quantities of gas to meet its Winter Checkpoint obligation to Union. Consequently, Union applied the Surplus Sale over Consumer Premium charge to the shortfall in gas quantities at the time of the Winter Checkpoint. This resulted in a charge of $2,007,250 for that gas to be paid by NRG to Union.

In the Board's Decision and Interim Order dated April 1, 2014, the Board approved recovery of $695,429 to cover the costs of the gas shortage at the time of the Winter Checkpoint on an interim basis until the Board establishes a process to further consider this matter and determine what the final payment should be to Union as a result of NRG being out of balance with respect to gas quantities. The $695,429 is based on the average price that NRG paid for the incremental gas that it was able to purchase in February. Accordingly, in the current QRAM application, NRG has included this amount in the cost of gas for the month of February 2014.

The Board has considered the evidence and finds that it is appropriate to adjust NRG's rates effective October 1, 2014 on an interim basis to reflect the projected changes in gas costs and prospective recovery of the projected twelve-month balances of the gas supply deferral accounts for the period ending September, 2015. The Board also finds that it is appropriate to adjust NRG's reference prices to reflect the projected changes in gas costs.

THE BOARD ORDERS THAT:

1. The rates approved for NRG as part of Interim Decision and Order EB-2014-0053 dated April 2, 2014 shall be superseded by the rates as provided in Appendix "A" and attached to this Interim Rate Order.

2. The rates shall be effective October 1, 2014 and shall be implemented in NRG's first billing cycle commencing in October 2014.

3. The reference price for use in determining the amounts to be recorded in the PGCVA (Account No. 179-27) shall decrease by $0.083607 per m^3 from the previous Board approved level of $0.315237 per m^3 to $0.231630 per m^3 as shown in Schedule "A" of Appendix "A" attached to this Rate Order.

4. The balance in the Gas Purchase Rebalancing Account shall be prospectively cleared. The resulting gas supply charge will decrease from the previous Board approved level of $0.325156 per m^3 to $0.262277 per m^3 as noted in Schedule "A" of Appendix "A" attached to this Rate Order.

5. The appropriate form of customer notice as set out in Appendix "C" shall accompany each customer's first bill or invoice following the implementation of this Order.

Issued at Toronto, September 25, 2014

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX “A” TO

DECISION AND ORDER

BOARD FILE No. EB-2014-0206

DATED: SEPTEMBER 25, 2014

NATURAL RESOURCE GAS LIMITED

RATE 1 - General Service Rate

Rate Availability

The entire service area of the Company.

Eligibility

All customers.

Rate

a)	Monthly Fixed Charge	$13.50
b)	Delivery Charge	
	First 1,000 m^3 per month	15.6601 cents per m^3
	All over 1,000 m^3 per month	10.6527 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)	Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE 2 - Seasonal Service

Rate Availability

The entire service area of the company.

Eligibility

All customers.

Rate

For all gas consumed from:		April 1 through October 31:	November 1 through March 31:
a)	Monthly Fixed Charge	$15.00	$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	14.5236 cents per m^3	18.3068 cents per m^3
	Next 24,000 m^3 per month	9.4826 cents per m^3	15.6960 cents per m^3
	All over 25,000 m^3 per month	6.1698 cents per m^3	15.2899 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)		Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading, provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE 3 - Special Large Volume Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a combined daily contracted demand for firm and interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 113,000 m^3.

Rate

1. Bills will be rendered monthly and shall be the total of:

a) A Monthly Customer Charge:

A Monthly Customer Charge of $150.00 for firm or interruptible customers; or
A Monthly Customer Charge of $175.00 for combined (firm and interruptible) customers.

b) A Monthly Demand Charge:

A Monthly Demand Charge of 29.0974 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.8521 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge and System Gas Refund Rate Rider (if applicable) Schedule A

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 3 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;
b) The load factor of the customer's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the customer during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE 4 - General Service Peaking

Rate Availability

The entire service area of the company.

Eligibility

All customers whose operations, in the judgment of Natural Resource Gas Limited, can readily accept interruption and restoration of gas service with 24 hours notice.

Rate

For all gas consumed from:		April 1 through December 31:	January 1 through March 31:
a)	Monthly Fixed Charge	$15.00	$15.00
b)	Delivery Charge		
	First 1,000 m^3 per month	15.1257cents per m^3	19.2963 cents per m^3
	All over 1,000 m^3 per month	10.5218 cents per m^3	16.9052 cents per m^3
c)	Gas Supply Charge and System Gas Refund Rate Rider (if applicable)		Schedule A

Meter Readings

Gas consumption by each customer under this rate schedule shall be determined by monthly meter reading provided that in circumstances beyond the control of the company such as strikes or non-access to a meter, the company may estimate the consumption each month as of the scheduled date of the regular monthly meter reading and render a monthly bill to the customer thereof.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE 5 - Interruptible Peaking Contract Rate

Rate Availability

Entire service area of the company.

Eligibility

A customer who enters into a contract with the company for the purchase or transportation of gas:

a) for a minimum term of one year;
b) that specifies a daily contracted demand for interruptible service of at least 700 m^3; and
c) a qualifying annual volume of at least 50,000 $m^{3.}$

Rate

1. Bills will be rendered monthly and shall be the total of:

a) Monthly Fixed Charge $150.00.

b) A Monthly Delivery Charge:

A Monthly Delivery Charge for all interruptible volumes to be negotiated between the company and the customer not to exceed 8.4612 cents per m^3 and not to be less than 5.4612 per m^3.

c) Gas Supply Charge and System Gas Refund Rate Rider (if applicable) Schedule A

d) Overrun Gas Charge:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, the customer should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to the customer on such day, or if, on any day, the customer fails to comply with any curtailment notice reducing the customer's take of gas, then

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any applicable Gas Supply Charge.

For any unauthorized overrun gas taken, the customer shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c) above, the matters to be considered include:

a) The volume of gas for which the customer is willing to contract;

b) The load factor of the customer's anticipated gas consumption and the pattern of annual use and the minimum annual quantity of gas which the customer is willing to contract to take or in any event pay for;

c) Interruptible or curtailment provisions;

d) Competition.

3. In each contract year, the customer shall take delivery from the company, or in any event pay for it if available and not accepted by the customer, a minimum volume of gas of 50,000 m^3. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this annual minimum shall be 7.0069 cents per m^3 for interruptible gas.

Bundled Direct Purchase Delivery

Where a customer elects under this rate schedule to directly purchase its gas from a supplier other than NRG, the customer or their agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to customers who elect said Bundled T transportation service.

Unless otherwise authorized by NRG, customers who are delivering gas to NRG under direct purchase arrangements must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE 6 – Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility

Rate Availability

Rate 6 is available to the Integrated Grain Processors Co-Operative, Aylmer Ethanol Production Facility only.

Eligibility

Integrated Grain Processors Co-Operative's ("IGPC") ethanol production facility located in the Town of Aylmer

Rate

1. Bills will be rendered monthly and shall be the total of:

a) Monthly Customer Charge of $150.00 for firm services

Rate Rider for reduction in Aid to Construct - effective until September 30, 2016 $(41,786.54)

b) A Monthly Demand Charge:

A Monthly Demand Charge of 18.3951 cents per m^3 for each m^3 of daily contracted firm demand.

c) A Monthly Delivery Charge:

(i) A Monthly Firm Delivery Charge for all firm volumes of 3.7976 cents per m^3,

(ii) A Monthly Interruptible Delivery Charge for all interruptible volumes to be negotiated between the company and IGPC not to exceed 10.9612 cents per m^3 and not to be less than 7.9412 per m^3.

d) Gas Supply Charge and System Gas Refund Rate Rider (if applicable) Schedule A

e) Overrun Gas Charges:

Overrun gas is available without penalty provided that it is authorized by the company in advance. The company will not unreasonably withhold authorization.

If, on any day, IGPC should take, without the company's approval in advance, a volume of gas in excess of the maximum quantity of gas which the company is obligated to deliver to IGPC on such day, or if, on any day, IGPC fails to comply with any curtailment notice reducing IGPC's take of gas, then,

(i) the volume of gas taken in excess of the company's maximum delivery obligation for such day, or

(ii) the volume of gas taken in the period on such day covered by such curtailment notice (as determined by the company in accordance with its usual practice) in excess of the volume of gas authorized to be taken in such period by such curtailment notice,

as the case may be, shall constitute unauthorized overrun volume.

Any unauthorized firm overrun gas taken in any month shall be paid for at the Rate 6 Firm Delivery Charge in effect at the time the overrun occurs. In addition, the Contract Demand level shall be adjusted to the actual maximum daily volume taken and the Demand Charges stated above shall apply for the whole contract year, including retroactively, if necessary, thereby requiring recomputation of bills rendered previously in the contract year.

Any unauthorized interruptible overrun gas taken in any month shall be paid for at the Rate 1 Delivery Charge in effect at the time the overrun occurs plus any Gas Supply Charge applicable.

For any unauthorized overrun gas taken, IGPC shall, in addition, indemnify the company in respect of any penalties or additional costs imposed on the company by the company's suppliers, any additional gas cost incurred or any sales margins lost as a consequence of the customer taking the unauthorized overrun volume.

2. In negotiating the Monthly Interruptible Commodity Charge referred to in 1(c)(ii) above, the matters to be considered include:

a) The volume of gas for which IGPC is willing to contract;
b) The load factor of IGPC's anticipated gas consumption, the pattern of annual use, and the minimum annual quantity of gas which IGPC is willing to contract to take or in any event pay for;
c) Interruptible or curtailment provisions;
d) Competition.

3. In each contract year, IGPC shall take delivery from the company, or in any event pay for it if available and not accepted by the IGPC, a minimum volume of gas as specified in the contract between the parties. Overrun volumes will not contribute to the minimum volume. The rate applicable to the shortfall from this minimum shall be 3.1530 cents per m^3 for firm gas and 5.4412 cents per m3 for interruptible gas.

4. The contract may provide that the Monthly Demand Charge specified in Rate Section 1 above shall not apply on all or part of the daily contracted firm demand used by the IGPC during the testing, commissioning, phasing in, decommissioning and phasing out of gas-using equipment for a period not to exceed one year (the transition period). In such event, the contract will provide for a Monthly Firm Delivery Commodity Charge to be applied on such volume during the transition of 5.7163 cents per m^3 and a gas supply commodity charge as set out in Schedule A, if applicable. Gas purchased under this clause will not contribute to the minimum volume.

Bundled Direct Purchase Delivery

Where IGPC elects under this rate schedule to directly purchase its gas from a supplier other than NRG, IGPC or its agent, must enter into a Bundled T-Service Receipt Contract with NRG for delivery of gas to NRG. Bundled T-Service Receipt Contract rates are described in rate schedule BT1. The gas supply charge will not be applicable to IGPC if it elects said Bundled T transportation service.

Unless otherwise authorized by NRG, IGPC, when delivering gas to NRG under direct purchase arrangements, must obligate to deliver said gas at a point acceptable to NRG, and must acquire and maintain firm transportation on all pipeline systems upstream of Ontario.

Delayed Payment Penalty

When payment is not made in full by the due date noted on the bill, which date shall not be less than 16 calendar days after the date of mailing, hand delivery or electronic transmission of the bill, the balance owing will be increased by 1.5%. Any balance remaining unpaid in subsequent months will be increased by a further 1.5% per month. The minimum delayed payment penalty shall be one dollar ($1.00).

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability

Entire service area of the company.

Eligibility

All customers served under Rates 1, 2, 3, 4, 5 and 6.

Rate

The Gas Supply Charge applicable to all sales customers shall be made up of the following charges:

PGCVA Reference Price	(EB-2014-0206)	23.1630 cents per m^3
GPRA Recovery Rate	(EB-2014-0206)	3.0284 cents per m^3
System Gas Fee	(EB-2010-0018)	0.0363 cents per m^3
Total Gas Supply Charge		26.2277 cents per m^3

Note:
PGCVA means Purchased Gas Commodity Variance Account
GPRA means Gas Purchase Rebalancing Account

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

RATE BT1 – Bundled Direct Purchase Contract Rate

Availability

Rate BT1 is available to all customers or their agent, who enter into a Receipt Contract for delivery of gas to NRG. The availability of this option is subject to NRG obtaining a satisfactory agreement or arrangement with Union Gas and NRG's gas supplier for direct purchase volume and DCQ offsets.

Eligibility

All customers electing to purchase gas directly from a supplier other than NRG must enter into a Bundled T-Service Receipt Contract with NRG either directly or through their agent, for delivery of gas to NRG at a mutually acceptable delivery point.

Rate

For gas delivered to NRG at any point other than the Ontario Point of Delivery, NRG will charge a customer or their agent, all approved tolls and charges incurred by NRG to transport the gas to the Ontario Point of Delivery.

Note:

Ontario Point of Delivery means Dawn or Parkway on the Union Gas System as agreed to by NRG and NRG's customer or their agent.

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

NATURAL RESOURCE GAS LIMITED

Transmission Service

Availability

Transmission Service charges shall be applied to Natural Resource Gas Corp.

Eligibility

Only Natural Resource Gas Corp. shall be charged the Transmission Service Rate. Fees and Charges will be applied only in those months that NRG Corp. delivers gas to a delivery point on NRG's system.

Rate

Administrative Charge	$250/month
Transportation Rate	$0.95/mcf

Effective: October 01, 2014
Implementation: All bills rendered on or after October 01, 2014
EB-2014-0206

APPENDIX “B” TO

DECISION AND ORDER

BOARD FILE No. EB-2014-0206

DATED: SEPTEMBER 25, 2014

NATURAL RESOURCE GAS LIMITED

Accounting Entries for the Purchased Gas Commodity Variance Account

Note: Account numbers are in accordance with the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

To record monthly as a debit (credit) in Deferral Account No. 179-27 (PGCVA) the decrease (increase) to reflect the projected changes in gas costs and prospective recovery of the balances of the gas supply deferral accounts approved by the Board for rate making purposes.

Debit/Credit Account No. 179-27 Purchased Gas Commodity Variance Account (PGCVA)

Credit/Debit Account No. 623 Cost of Gas

To record as a debit (credit) in Deferral Account No. 179-28, interest on the balance in Deferral Account

Debit/Credit Account No. 179-28 Purchased Gas Commodity Variance Account (PGCVA)

Credit/Debit Account No. 323 Other Interest Expense

Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

APPENDIX “C” TO

DECISION AND ORDER

BOARD FILE No. EB-2014-0206

DATED: SEPTEMBER 25, 2014

IMPORTANT INFORMATION ABOUT YOUR GAS BILL

On all bills rendered by NRG on or after October 1, 2014, the price we charge for the gas commodity and transportation portion of your bill will be decreasing by $0.062879 per cubic meter to $0.262277 per cubic meter. The Ontario Energy Board (OEB) has approved this change to reflect the prices that NRG expects that it will be paying to its gas suppliers through to the end of September, 2015. On your gas bill this cost is on the line entitled “Gas Commodity”.

As a regulated utility, NRG is permitted to recover what it pays for the purchase of gas plus any costs reasonably associated with this purchase but with no mark up or ‘profit’. The price the utility charges you is based on the forecasted gas and transportation costs to NRG, which are periodically reviewed by the OEB and reconciled with actual costs. The gas commodity portion gets adjusted regularly throughout the year as the price of the gas commodity changes.

How will this price change impact you? That will depend on the amount of gas that you use. For a typical residential customer who consumes approximately 2,009 cubic meters of gas annually, this price change will cause your annual heating costs to decrease by approximately $126 per year. For customers who have arranged to have their gas supplied by a gas marketer/broker, the price may or may not change depending on the terms of the contract the customer has with the gas marketer/broker.

If you have any questions about this rate change, please do not hesitate to contact us at 519-773-5321. We thank you for continuing to make natural gas your fuel of choice.

Ontario Energy Board
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BY E-MAIL AND WEB POSTING

November 25, 2013

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2014 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2014 Cost of Service Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2014 cost of service applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2014 Rates

For rates with effective dates in 2014, the Board has updated the Cost of Capital parameters based on: (i) the September 2013 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:-(A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2014 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2014 cost of service rate applications for rates with effective in 2014 are:

Cost of Capital Parameter	**Value for 2014 Cost of Service Applications for rate changes in 2014**
ROE	9.36%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board intends to update Cost of Capital parameters for setting rates in cost of service applications only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service applications with rates effective in the 2014 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in support of different Cost of Capital parameters due to the specific circumstances in individual rate hearings, but must provide strong rationale for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For Cost of Service rate changes effective in 2014)

Cost of Capital Parameter Calculations

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2013

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
	Day	10-yr	30-yr	30-yr		
1	1-Sep-13					
2	2-Sep-13					
3	3-Sep-13	2.68	3.15	4.61	0.47	1.46
4	4-Sep-13	2.71	3.18	4.63	0.47	1.45
5	5-Sep-13	2.80	3.25	4.72	0.45	1.47
6	6-Sep-13	2.76	3.23	4.70	0.47	1.47
7	7-Sep-13					
8	8-Sep-13					
9	9-Sep-13	2.74	3.22	4.69	0.48	1.47
10	10-Sep-13	2.82	3.28	4.75	0.46	1.47
11	11-Sep-13	2.78	3.26	4.73	0.48	1.47
12	12-Sep-13	2.78	3.26	4.73	0.48	1.47
13	13-Sep-13	2.76	3.25	4.73	0.49	1.48
14	14-Sep-13					
15	15-Sep-13					
16	16-Sep-13	2.79	3.28	4.76	0.49	1.48
17	17-Sep-13	2.77	3.26	4.77	0.49	1.51
18	18-Sep-13	2.70	3.21	4.69	0.51	1.48
19	19-Sep-13	2.70	3.22	4.74	0.52	1.52
20	20-Sep-13	2.69	3.20	4.69	0.51	1.49
21	21-Sep-13					
22	22-Sep-13					
23	23-Sep-13	2.65	3.17	4.67	0.52	1.50
24	24-Sep-13	2.59	3.11	4.63	0.52	1.52
25	25-Sep-13	2.57	3.09	4.60	0.52	1.51
26	26-Sep-13	2.58	3.10	4.61	0.52	1.51
27	27-Sep-13	2.55	3.08	4.56	0.53	1.48
28	28-Sep-13					
29	29-Sep-13					
30	30-Sep-13	2.54	3.07	4.56	0.53	1.49
31						
		2.70	3.19	4.68	**0.496**	**1.483**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Publication Date: September 9, 2013

	3-month	12-month		Average	
September 2013	2.700	3.100	❸	**2.900**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.900	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.496	%
Long Canada Bond Forecast (LCBF)	❹	**3.396**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75	%
Change in Long Canada Bond Yield Forecast from September 2009					
LCBF (September 2013) (from Step 3)	④	3.396	%		
Base LCBF		4.250	%		
Difference		-0.855	%		
0.5 X Difference				-0.427	%
Change in A-rated Utility Bond Yield Spread from September 2009					
A-rated Utility Bond Yield Spread (September 2013) (from Step 1)	②	1.483	%		
Base A-rated Utility Bond Yield Spread		1.415	%		
Difference		0.068	%		
0.5 X Difference				0.034	%
Return on Equity based on September 2013 data				**9.36**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2013 (from Step 3)	④	3.396	%
A-rated Utility Bond Yield Spread September 2013 (from Step 1)	②	1.483	%
Deemed Long-term Debt Rate based on September 2013 data		**4.88**	%

Ontario Energy Board
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Attachment: Cost of Capital Parameter Calculations
(For Cost of Service rate changes effective in 2014)

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance		Date of input
Bank 1	100.0	bps	Sept., 2013
Bank 2	100.0	bps	Sept., 2013
Bank 3	82.5	bps	Sept., 2013
Bank 4	80.0	bps	Sept., 2013
Bank 5			
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	4	
High estimate	100.0	bps
Low estimate	80.0	bps

C. Average annual Spread	91.250	bps	❶

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.913	%	①
Average Bankers' Acceptance Rate	1.200	%	②
Deemed Short Term Debt Rate	**2.11**	%	

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2013

Month: **September 2013**

	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-13		
2	2-Sep-13	Bank holiday	%
3	3-Sep-13	1.20	%
4	4-Sep-13	1.20	%
5	5-Sep-13	1.20	%
6	6-Sep-13	1.20	%
7	7-Sep-13		
8	8-Sep-13		
9	9-Sep-13	1.20	%
10	10-Sep-13	1.20	%
11	11-Sep-13	1.20	%
12	12-Sep-13	1.20	%
13	13-Sep-13	1.20	%
14	14-Sep-13		
15	15-Sep-13		
16	16-Sep-13	1.20	%
17	17-Sep-13	1.20	%
18	18-Sep-13	1.20	%
19	19-Sep-13	1.20	%
20	20-Sep-13	1.20	%
21	21-Sep-13		
22	22-Sep-13		
23	23-Sep-13	1.20	%
24	24-Sep-13	1.20	%
25	25-Sep-13	1.20	%
26	26-Sep-13	1.20	%
27	27-Sep-13	1.20	%
28	28-Sep-13		
29	29-Sep-13		
30	30-Sep-13	1.20	%
31			
		1.200	%
		❷	

Source Bank of Canada / Statistics Canada
Series V39071

Reference on Calculation Method:
- Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.