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August 25, 2014

Patrick G. Welsh
Direct Dial: 416.862.5951
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Our Matter Number: 1151071

Sent by Courier and RESS Electronic Filing

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

Dear Ms. Walli:

EB-2014-____ – 2014-2015 Rates Application – Natural Resource Gas Limited

Please find enclosed an Application by Natural Resource Gas Limited for an Order or Orders made pursuant to section 36 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other charges for the distribution and sale of natural gas for a period of two years, commencing October 1, 2014.

We will forward two paper copies of this Application to you by courier.

Yours very truly,

Patrick G. Welsh
Associate

PW:ls
Enclosures

c:

Richard King, *Osler, Hoskin & Harcourt LLP*
Laurie O'Meara, *NRG*

EB-2014-____

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, pursuant to section 36 of the *Ontario Energy Board Act*, *1998*, for an Order or Orders approving or fixing just and reasonable rates and other charges for the distribution and sale of natural gas for a period of two years.

APPLICATION OF
NATURAL RESOURCE GAS LIMITED

August 25, 2014

OSLER, HOSKIN & HARCOURT LLP
Box 50, 1 First Canadian Place
Toronto, ON   M5X 1B8

Richard J. King
Tel: 416.862.6626

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Tel: 416.862.5951
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Counsel for Natural Resource Gas Limited

EXHIBIT LIST

Exhibit	Tab	Schedule	Contents of Schedule
Administration			
A	1	1	Exhibit List
		2	Application
		3	Procedural Orders/Motions/Correspondence
	2	1	Natural Gas Service Rules and Regulations
		2	Schedule of Service Charges
	3	1	NRG's Audited Financial Statements (2013)
		2	NRG's Audited Financial Statements (2012)
		3	NRG's Audited Financial Statements (2011)
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Overview			
B	1	1	Summary of the Application
Rationale for Extension of IR Plan			
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		2	• ROE Calculations
	2	1	Regulatory Efficiencies
	3	1	Outstanding Item from Previous Rate Case
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		2	• Consolidated Financial Statements 2009
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		6	• *Globe and Mail* Article (February 2013)
		7	• Correspondence between IGPC and NRG
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Financial Information/Security from IGPC			
D	1	1	Financial Information/Security from IGPC
		2	• Gas Delivery Contract
		3	• Pipeline Cost Recovery Agreement
		4	• Existing Delivery Letter of Credit
		5	• Letter re: Next Reduction to Letter of Credit

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Natural Resource Gas Limited for an Order or Orders pursuant to section 36 of the OEB Act approving or fixing just and reasonable rates and other charges for the sale, transmission and distribution of natural gas as of October 1, 2014.

APPLICATION

1. Natural Resource Gas Limited ("NRG"), an Ontario corporation, carries on the business of distributing and selling natural gas in southern Ontario.

2. NRG hereby applies to the Ontario Energy Board (the "Board") for an Order or Orders made pursuant to section 36 of the OEB Act approving or fixing just and reasonable rates and other charges for the distribution and sale of natural gas for a period of two years, commencing October 1, 2014.

3. For the purpose of subsection 36(3) of the OEB Act, NRG seeks the Board's approval of:

   (a) distribution rates based on a continuation of NRG's current Incentive Regulation ("IR") Plan for NRG's next two fiscal years from October 1, 2014 through September 30, 2016 (the "2015 Fiscal Year" and "2016 Fiscal Year");

   (b) NRG's existing transportation rate (for use of NRG's distribution system by producers selling gas to Union Gas Limited) of $0.95 per mcf and an administrative charge of $250 per month for every month a producer uses the NRG distribution system;

(c) NRG's Rules and Regulations and its Schedule of Service Charges in the form as approved in EB-2010-0018;

(d) a deferral account to record costs associated with NRG implementing a new DSM program commencing January 1, 2015;

(e) a requirement that Integrated Grain Processor Co-operative Inc./IGPC Ethanol Inc. ("IGPC") provide NRG with: (i) updated financial statements; (ii) information as to the status and likely renewal of IGPC's operating grants; (iii) information about IGPC's business plans if the operating grants are not extended or renewed beyond 2016; (iv) information about IGPC's natural gas requirements (volume and term) upon expiration of the current Gas Delivery Contract in April 2015; and (v) updated security for undepreciated capital costs beyond November 2015;

(f) NRG's current rates on an interim basis as of October 1, 2014; and,

(g) such further and other relief as NRG may request and the Board may grant.

4. NRG further applies to the Board, pursuant to the provisions of the OEB Act and the Board's *Rules of Practice and Procedure*, for such final, interim or other Orders and directions as may be appropriate in relation to the Application and the proper conduct of this proceeding.

5. This Application will be supported by written, and if necessary, oral evidence. The written evidence will be pre-filed (and may be amended from time to time as circumstances may require).

6. NRG requests that this proceeding be disposed of by way of a written hearing.

7. The persons affected by this Application are the present and future customers of NRG. It is impractical to set out in this Application the names and addresses of such parties because they are too numerous.

8. NRG requests that a copy of every document filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

Laurie O'Meara
Natural Resource Gas Limited
c/o P.O. Box 3117, Terminal A
London, ON M6A 4J4

Tel: (519) 433-8126, ext. 216
Fax: (519) 433-6132
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-and-

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-and-

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Tel: (416) 862-5951
Fax: (416) 862-6666
Email: pwelsh@osler.com

DATED at Toronto, Ontario this 22nd day of August, 2014.

NATURAL RESOURCE GAS LIMITED

By its counsel, Osler, Hoskin & Harcourt LLP
Per: Richard J. King

NATURAL RESOURCE GAS LIMITED

NATURAL GAS SERVICE

RULES & REGULATIONS

Effective August 1, 1995

Revised October 1, 2009

TABLE OF CONTENTS

1. INITIATION OF SERVICE

1.1 APPLICATIONS

The Company may, at its discretion, accept applications for gas service on existing service laterals or new service laterals. Each applicant must complete an Application for Gas Service in the form attached as Schedule 1A. Any business or company making application must also complete a Credit Application in the form attached as Schedule 1B. The applicant must complete both sides of the blue copy and will receive the yellow copy for their records after approval.

The only exception to the above shall be in the case of contract rate customers. Contract rate customers are required to execute a contract for a specified term of not less than one year.

The Company will charge a $30.00 transfer/connection charge, plus applicable taxes, on all approved applications, which will be charged on the first gas billing.

1.2 SECURITY DEPOSITS (as per EB 2008-0413)

General:
After an application for Gas Service is completed, the Credit Department will run a credit check and determine if a security deposit is required (outlined further below).The Security Deposit must be paid before connection can occur.

Determination of Security Deposit (All Residential & Commercial Customers)
The security deposit is determined based on the average monthly consumption of gas during the last 12 consecutive months, within the past two years, at the specific address in which the gas service is installed or will be installed. Note this is for new customers or for customers who no longer have a good payment history (defined below).

The maximum amount of a security deposit NRG may require a consumer to pay shall be calculated as follows:

> Billing cycle factor 2.5 X average annual consumption over past 12 consecutive months or consumers estimated consumption, or a reasonable estimate made by NRG.

Security deposits will not be required:

- If a consumer is residential or general service, and a satisfactory credit check has been conducted, at the time of application. A beacon score of 680 + and a credit utilization of less than 50% will be required.

- If a consumer can provide a letter from another gas/ electricity distributor in Canada confirming good payment history.

- A good payment history (definition below): 1 year residential/ 5 years general service/ 7 years for other

- Definitions: "general service consumer" means a consumer that is not a residential consumer and that annually consumes no more than 100,000m^3 of gas.

- The time period that makes up a good payment history is the most recent period of time, and must have occurred in the past 24 months

  Unconditional "Letters of Credit" from a customer's banker in an appropriate amount or a personal guarantee from the owners may be accepted in lieu of cash security on commercial and industrial accounts.

Definition of Good Payment History:

- If a consumer has received more than one disconnection notice from NRG, or another gas vendor in the past 12 months

- If a consumer has more than one NSF cheque: returned by reason of insufficient funds.

- If a consumer has more than one NSF cheque from a pre- authorized payment plan

- If a consumer has had at least one visit, from NRG, to the consumer's premises, for purpose of payment of an overdue amount, or to shut off or limit the gas supply to the consumer's premises for non-payment.

Security Deposit Refunds

- Annual reviews are conducted on all accounts to determine if consumer is entitled to a refund, or an adjustment is required.

- Requests for a refund of security deposits can be made after 1 year of service (residential) / 5 years (General accounts) 7 years (Other accounts) must be made in writing to our Credit department.

- Security deposit will not be refunded if the customer does not have a good payment history (as defined above).

- Security deposit will either be given by a cheque or a credit to the customer.

Interest on Security Deposits

Interest accrued on security deposits will be credited to the customers' account on an annual basis. The interest rate shall be the Prime Business Rate published on the Bank of Canada Website less 2 % updated quarterly.

For any quarter that the PBR is 2 percent or less the interest rate will be 0.

Security Deposits and Cancellation of Service
When a customer discontinues service, a Cancellation Service form is filled out. After the final billing period has been processed, and the account is settled in full, the Security Deposit will be refunded to the customer.

If the customer's account is not settled in full prior to requesting the refund, the Security deposit will be applied to unpaid balance and any remaining Security Deposit will be refunded to the customer.

Transfer of Security Deposits
If a customer should move to another location that is serviced by Natural Resource Gas Limited the Security Deposit is reviewed, and adjusted according to the for Security Deposits requirements
A Security Deposit may increase or decrease depending on the consumption of the new location, and past history of the consumer's account.

Third Party Security Deposits

As per The Ontario Energy Board amendments to the gas distribution access rule (GDAR IN EB) 2008-0413 APPENDIX B MAY5/2009

Where all or part of a security deposit has been paid by a third party on behalf of a consumer, NRG shall return the amount of the security deposit paid by the third party, including interest where applicable, to the third party. This obligation shall apply where and to the extent that:

(a) The third party paid all or part (as applicable) of the security deposit **directly**, to NRG;

(b) The third party has requested, at the time the security deposit was paid or within a reasonable time thereafter, that NRG return all or part (as applicable) of the security deposit to them rather than to the consumer; and

(c) There, is not then any amount overdue for payment by the consumer, that, NRG is permitted by this Rule to off set using the security deposit.

1.3 MAIN EXTENSIONS

The Company will make extensions of its mains to some applicants when, in the sole discretion of the Company, the main extension is economically feasible.

When the extension is not economically feasible, the applicant will be required to pay an "Aid to Construction" in an amount determined by the Company to make the project economically feasible.

1.4 SERVICE LATERAL INSTALLATIONS

Service laterals will only be installed provided that:

(i) an application (contract) has been properly completed and approved,
(ii) any deposit required has been collected,
(iii) any main extension can be justified in accordance with the Company's line extension practice, and
(iv) any charges for service lateral installation in accordance with the following have been paid

All Customers - A gas service lateral extending from the property line to the meter location selected by the Company will be installed for a fee of $ 100.00 for the first 20 meters plus an additional charge of $ 10.00 per meter thereafter.

Meter Set Locations are determined as follows:

a) For residential customers, meters may be located on the front or on either side of the dwelling in which it serves. If the meter is located along one of the sides of the dwelling, the distance from the front corner to the meter location cannot exceed 10 feet.

b) All meter set locations must comply with the Technical Standards and Safety Act and Codes and Standards Adopted by Regulation.

c) When the distance from the property line to a dwelling or building requiring the gas service exceeds 100 meters, it may be required that the meter be located near the property line. In these cases, a cost estimate must be done to determine the outlet cost of underground piping from the meter set to the building.

1.5 CUSTOMER PIPING

Applicants for service shall, at their own expense, equip their premises with all piping and attachments from the meter to the appliances or equipment served. It is the customer's responsibility to maintain the piping and equipment beyond the outlet side of the meter. Such piping and attachments shall be installed and maintained in accordance with the rules of the Company and the Technical Standards and Safety Act and Codes and Standards Adopted by Regulation.

Meters will not be connected with customer's piping when that piping and/or appliances or heating equipment attached thereto are known by the Company to be defective or not in accordance with applicable rules and regulations, ordinances or codes. The Company reserves the right to discontinue service at any time it finds the piping, venting, appliances or other gas-fired equipment on customer's premises defective or in an unsafe condition.

The customer is expected to immediately notify the Company of any leakage or escape of gas on his premises.

1.6 INSPECTION OF NEW AND EXISTING INSTALLATIONS

All inspections shall conform to the "Ontario Energy Act" and the "Technical Standards and Safety Act and Codes and Standards Adopted by Regulation" and amendments in force at the time of inspection.

All new installations of supply piping and gas appliances on premises served with gas for the first time require inspection to ensure that they are in accordance with legislative requirements.

A general inspection will be made of gas appliances and installations:

- (a) whenever a meter is initially installed,
- (b) whenever a meter is changed,
- (c) whenever a meter is physically reset on an inactive service or account, or
- (d) in accordance with the requirements of the Ontario Energy Act

A modified inspection will be made of vented gas appliances:

- (a) whenever a previously inactive account is reactivated,
- (b) when a meter is turned on after credit lock offs, seasonal turn offs or routine repairs to mains or services, or
- (c) when vented equipment is lit up after component replacement

2. MAINTENANCE OF SERVICE

2.1 MAINTENANCE

The Company and its authorized representatives shall have the right to enter upon the premises of the customer at all reasonable times, upon reasonable notice, to read, inspect, test, repair, replace or remove meter and regulator equipment.

2.2 TESTING METERS

Meters will be tested at the Company's option or at the request of the customer or when required by legislative requirements. When a meter is tested at the customer's request, the Company will collect from the customer any cost involved in the removal, testing, Government inspection and meter replacement where it is determined that the meter was within acceptable tolerances.

2.3 SERVICE DEPARTMENT CHARGES

The Company provides regular service during the normal working hours, and emergency service 24 hours per day.

(i) *Charge for Service to Customer Owned Appliances*

Repairs will be performed on a time and material basis in accordance with the Company's prevailing parts and labour prices, except when covered by Company or manufacturer's warranties.

(ii) *Charge for Service to Company Owned Appliances*

The Company agrees to supply such maintenance as in the judgement of the Company is required for the proper use of the appliance at no charge to the customer.

(iii) The Company does not charge for leak complaints, insufficient gas supply, and inspection of appliances in accordance with Government Regulations. Repairs required to remedy gas leaks and insufficient supply of gas from causes downstream of the meter will be charged on a time and material basis.

2.4 CUSTOMER SERVICE WORK

The following are the rates currently in effect by the company. These rates are subject to amendment from time to time.

Regular Hours

Minimum charge (up to 60 minutes)	$67.00
each additional half hour (or part thereof)	$30.00

After Hours

Minimum charge (up to 60 minutes)	$110.90
each additional half hour (or part thereof)	$58.10

Disconnection- Non Payment or Discontinuance of Service (i.e. seasonal)

Flat Fee	$78.00

Customer Transfer/Connection Charge

Flat Fee	$30.00

Applicable taxes will also be added to the above charges.

3. RENTAL EQUIPMENT

3.1 MONTHLY RENTALS

The Company rents water heaters. Water softeners are also rented on a rent to own basis. The rates for water heaters are as indicated below:

Conventional Models	
40 US Gallon	$ 10.75 monthly
50 US Gallon	$ 12.50 monthly
60 US Gallon	$ 15.00 monthly
Power Vented or Direct	
40 US Gallon	$19.00 monthly
50 US Gallon	$21.00 monthly
60 US Gallon	$22.00 monthly
50/65 US Gallon	$23.00 monthly
50 DV US Gallon	$21.00 monthly
Tankless Water Heater	$34.50 monthly

The rental for water heaters other than those listed above will be calculated by the General Manager.

3.2 INSTALLATION COSTS

The customer bears the initial installation cost of all equipment. Such installation done by NRG is generally done on a quoted basis. NRG may, from time to time, offer installation assistance through its marketing and promotion efforts. The cost of installing replacement units still under warranty is borne by the Company.

3.3 RENTAL AGREEMENT

Prior to installation of a rental water heater, or removal from inventory for rental, a Rental Agreement form must be completed by the customer in the form attached as Schedule 2. The blue copy remains in the office, the yellow copy is returned to the customer after insertion of the installation and contract dates, and serial and Company numbers.

A Rental Agreement must also be completed by an applicant who is moving into a property where a rental water heater exists. The form can be fully completed at the time of application, and the yellow copy may be given to the customer at that time for his records.

4. BILLINGS & COLLECTIONS

4.1 BILLINGS & COLLECTIONS

Bills will be issued and payable monthly and must be paid at or mailed to the office of the Company, an established collection agency of the Company, or at any chartered bank authorized by the Company.

Bills for gas service furnished by the Company are due when rendered. For customers paying their bill after sixteen days from the billing date, a late payment charge will apply (see section 4.2).

Bills will be mailed to the customer at the last known address as shown on the Company records, unless the customer has directed the Company to send the bill to another address.

Gas consumed will be based on meter readings, or estimates with an estimated bill issued for interim months, and will be computed on the applicable rate schedule approved by the Ontario Energy Board. Any necessary adjustments due to estimated bills will be made on the next regular billing.

A claim for an error in billing should be made by the customer as soon as discovered. If in the opinion of the Company the claim is valid, the Company will make a proper adjustment to the bill.

Where billing errors have resulted in overbilling, the customer will be credited with the amount erroneously paid for a period not exceeding six years.

Where billing errors have resulted in under-billing, the customer shall be charged with the amount erroneously not billed for a period not exceeding:

(a) two years, in the case of an individual residential customer who was not responsible for the error, and

(b) six years, in other cases.

The timing for billings and notices etc., will be as follows. The days represent the days after the end of a billing cycle (e.g. if a normal billing cycle ended on the 14th of the month, day one would commence on the 15th).

Day 1 to 3	Reading, billing and mailing of invoices
Day 13 to 15	Bills due
Day 30	Final Disconnection Notices are mailed for past due accounts. See comments in section 5.1 Disconnection & Reconnection – non-payment.

Day 45	Credit department determines if customer is to be disconnected. See section 5 Disconnection & Reconnection of Service.

4.2 DELAYED PAYMENT

Payments made after sixteen days after the billing date will be considered late and those accounts will have their balances increased by 1.5% of the amount unpaid after sixteen days. Payments made at any chartered bank will be considered paid on the date payment is made to the bank. Any amounts unpaid for subsequent months will be increased by a further 1.5% for each billing cycle that the balance remains unpaid. The minimum increase will be $1.00.

4.3 PAYMENT BY MAIL

When payments are made by mail, bills will be considered to have been paid one day prior to the postmark date.

4.4 BUDGET BILLING PLAN

The budget plan for payment of gas bills is designed to equalize the monthly payments for gas service of residential customers using gas for heating purposes and is available to any heating customer who can establish satisfactory credit with the Company.

New residential heating customers and existing heating customers with satisfactory credit and no balance outstanding may be enrolled in the plan at their request. Customers may withdraw from the plan at any time upon notification to the Company.

The Company will estimate the aggregate amount of the customer's bill for gas service for a normal year's operation from June to April. Such estimated amount will then be divided by eleven, rounded up to the next $5.00 or $10.00 amount, and shall be the monthly budget instalment the customer will pay in lieu of the regular monthly billing

Bills for the month of May will be computed for settlement of the account either by the customer paying the excess of actual charges incurred over the sum of budget payments made, or by the Company crediting to the customer any credit balance then existing. This budget to actual difference will be added or subtracted, as the case may be, to the actual gas charges incurred on bills for the month of May.

Any estimate furnished by the Company in connection with such payment plan shall not be construed as a guarantee or assurance that the total actual charges will not exceed the estimates. The Company may at any time submit a revised estimate to the customer and require that the customer pay the revised monthly budget instalment as a condition to the continuation of the budget payment plan for that customer.

Such estimates shall apply only to the premises then occupied by the customer. If the customer vacates such premises, the budget payment plan with respect to those premises, and for that customer, shall immediately terminate and any amount payable by the customer shall be paid or any amount due to the customer by the Company shall be refunded.

Non-payment of budget will result in the customer receiving a disconnection notice and possibly removed from the budget plan. The account will be reconciled on the following billing cycle, and the customer will be responsible to bring the account up to-date.

4.5 GROUP BILLINGS

Combinations of reading from several meters may be done at the Company's sole discretion.

Group billing will be permitted only in special situations at the discretion of the Company.

5. DISCONNECTION & RECONNECTION OF SERVICE

5.1 DISCONNECTION & RECONNECTION - NON PAYMENT

Disconnection notices are mailed on Day 34 after the end of billing cycle. The customer is given until Day 45 to pay balance due before they are disconnected. In addition, Credit Department will call all customers 2 days before disconnection date if payment has not been received. If customer can still not pay by due date or no effort to work out a repayment plan can be made the customer will be disconnected.

DISCONNECTION OF SERVICE FOR NON PAYMENT

- If it has been determined that a customer will not pay and the account must be locked for non payment.
- A lock form is prepared and authorized by the Credit Department and Approved by the General Manager.
- A copy of the Lockout form is given to service to set the call to lock the account.
- Customers receive a hand delivered notice at time of locking the meter explaining the disconnection of service

If a customer should be disconnected for non-payment and then reconnected, the following charges will be added to the account

- Disconnection charge 78.00
- Reconnection charge 78.00

plus Applicable taxes

Payment of the reconnection charge must be made before reconnection can occur and an increase in security deposit or a security deposit may be required before reconnection of service is made. Amount is determined as outlined in section 1.2.

Non-Payment of Accounts

Definition of Accounts = past work orders, accounts locked for non-payment and customers that have moved and have a balance outstanding.

If the customer is unresponsive, or refuses to pay further collection action may take place, which is outlined below:

- If a customer refuses to pay on the account or does not follow a payment schedule legal action will commence.
- Customers will be notified that a claim has been issued for small Claims court.
- Court Documents will be filed, and Court procedures used to collect money owing
- Any court costs, incurred by Natural Resource Gas Limited, for the collection of money will be added to the customer's debt, as allowed by Small Claims Court.
- Will be forwarded to the Credit Bureau of St. Thomas for collections and the debt will be reported to Equifax on the customers credit file.

5.2 DISCONTINUANCE FOR CAUSE OTHER THAN NON-PAYMENT

Service may be discontinued by the Company at any time to prevent fraudulent use or to protect its property.

The Company further reserves the right upon discovery of any condition of the customer's appliance or piping which is, in the opinion of the Company, immediately hazardous to life and property, to discontinue gas service until such time as the hazardous conditions shall be remedied.

5.3 DISCONTINUANCE ON CUSTOMER'S ORDER

The agreement between the customer and the Company created by the acceptance of the customer's request for gas service, where no contract for a main extension or term of service is involved, shall continue in full force and effect until terminated by the customer (except as provided under Sections 5.1 and 5.2) giving sufficient notice to a Company business office relative to the intent to discontinue service. The customer shall be liable for all gas supplied to the premises and safe custody of the Company's property until service is discontinued in accordance with the customer's instructions. When a customer requests disconnection of service within 90 days of connection, a disconnection charge of $78.00 plus applicable taxes will be applied to the final billing.

5.4 TEMPORARY DISCONTINUANCE OF SERVICE

Customers who temporarily discontinue service during any twelve consecutive months without payment of a monthly fixed charge for the months, in which the gas is temporarily disconnected, shall pay for disconnection and reconnection.

Natural Resource Gas Limited
PO Box 307, 39 Beech St. E.
Aylmer, Ont. N5H 2S1

Natural Resource Gas Limited
Application for Gas Service

Service Department
Aylmer: 519-773-5321
Fax: 519-773-5335

______________________ 20 ______

I/WE ____ (the "Customer")

apply to Natural Resource Gas Limited ("the Company") for gas service at ______________________________

____ (the "premises")

according to the following terms and conditions:

1. The Customer agrees to pay accounts when due.
2. Customer agrees that a meter connection will be established immediately after the installation of the service line and will be subject to the monthly fixed charge from that date.
3. Customers intending to vacate premises supplied with gas or to discontinue the use of gas shall give notice to the Company at 39 Beech Street E., Aylmer, Ontario or other such address as customer may be advised, fifteen (15) days before the Customer intends to discontinue service and in default of providing such notice, the Customer will remain liable for all gas which passes through the meter until such notice is given. In the event accounts for natural gas, rentals or other services are not paid in accordance with this agreement and collection procedures are made by the Company and/or its agent, Customers will be liable for collection costs incurred by the Company and/or its agent. _____ X
4. If the Customer discontinues service within ninety (90) days of application for gas service, there will be a charge for removal plus GST, or such charge as is currently in effect by the Company which will be added to the final billing and/or deducted from the original deposit.
5. The Company may discontinue service and disconnect and remove the meter for repair, lack of supply and/or non-payment of bills (including late penalty charges) when due. The original deposit will be refunded upon full payment of any outstanding amount.
6. Gas will be supplied to a meter installed by the Company. If that meter should fail to register the quantity of gas consumed or if access to read the meter cannot be made, the account of the Customer will be estimated by the Company.
7. Customer agrees to give immediate notice at the office of the Company of any escape of gas. In case of a leak, the stop-cock at the meter must be immediately closed and no light taken near the escape until after free and full ventilation.
8. Except in the case of an emergency, the Company and/or its authorized agent shall at all reasonable hours, have access to the premises for the purposes of examining, regulating or repairing the gas apparatus installed, ascertaining the quantity of gas consumed or supplied and/or to discontinue or remove the meter. In the case of an emergency, the Company and/or its authorized agents shall have access to the premises at any hour.
9. The Company shall not be liable for any damages or losses resulting from any failure to supply. The Customer agrees with the Company that the Company will not be held liable by the Customer for any loss, damage, injury or delay to any person or to any property resulting from the transportation, storing or any use of the gas supplied to the premises including any damage or loss from explosion or fire. Further the Customer agrees to indemnify and save harmless the Company from and against all claims and demands arising out of the transportation, storing or use of the gas supplied to the Customer's premises including any loss or damage from explosion or fire made by any person and from and against all damages, losses, costs, charges and expenses which the Company may sustain or incur and be liable for as a consequence of any such claim or demand.
10. The Customer acknowledges that there will be a late charge on the past due amount (minimum $1.00) if the bill is not paid within sixteen (16) days of rendering and there will be a monthly fixed charge of $______________ . _____ X
Both of the charges are subject to revision and approval by the Ontario Energy Board.
11. The Customer acknowledges that there will be a transfer/connection charge of <u>$30 plus GST</u>, or as may be ordered by the Ontario Energy Board, which will be charged on the first billing. _____ X

SIGNATURE OF APPLICANT ____

DEPOSIT RECEIVED: $ ____________________ DEPOSIT RECEIVED BY: ____________________

PREMISES OWNED BY: ____

SEE REVERSE FOR CREDIT APPLICATION

APPLICATION FOR GAS SERVICE

Date of Application:____________________ Date Service Req'd:________________ 20____

☐ Residential ☐ Commercial ☐ Industrial ☐ Seasonal

Last Name First Name Initial	Date of Birth MM/DD/YY	Martial Status Married ☐ Single ☐	Spouse Name	No. of Dependents

Service Address	Home Phone #

Mailing Address	Drivers Lic. No.
Name of Landlord & Address (If Applicable)	Social Ins. No.

Employer Name & Address	Position	How Long	Business Phone #
Spouse's Employer Name & Address	Position	How Long	Business Phone #

Previous Address	How Long

Previous Employer Name & Address	Position	How Long
Spouse's Previous Employer Name & Address	Position	How Long

Bank	Credit Cards	
Name	Name	Name
Branch	Branch	Branch

Nearest Relative (Not Living with Applicant)	Relationship	Address	Phone #
Other Personal Reference	Relationship	Address	Phone #

Some of the information contained in this application constitutes "personal information" and is thereby covered under Federal privacy legislation. NRG obtains this information in order to bill for the products identified in this agreement, repairs and service to the equipment and for collections of arrears of amounts owing under this agreement. NRG does not share this information with third parties with the exception of consultants, professional advisors and regulatory bodies. All of these parties are bound by their own privacy obligations which restricts further dissemination of such information.

The undersigned agree(s) that a personal investigation may be conducted or a credit report obtained in respect of this contract

Signature of Applicant:________________________________

Notes

____

____

____

____

____

NATURAL RESOURCE GAS LIMITED - RENTAL AGREEMENT

NRG, please supply the following goods to:	Owner ☐	Tenant ☐	Builder ☐	Telephone Number
Address	City	Postal Code		Contract Date
Installation Address (if other than above)	City	Postal Code		Bill as Rental Only

ADDITIONS	Gas to Gas ☐	Builder ☐		Other Fuel to Gas ☐	Other ☐
REPLACEMENTS GAS TO GAS	Upgrade ☐	Leaker ☐		Limed Up ☐	Other (specify) ☐
DELETIONS	Demolitions ☐	Rental to Sale ☐	Gas to Gas ☐	Gas to Other Fuel ☐	Other ☐

Natural Resource Gas (hereinafter called NRG) leases to the Customer and the Customer rents from NRG the following:

Equipment	Water Heater Size	Description of Equipment	Monthly Rental $	TAX	Yes	No
Res. ☐						
Comm. ☐				GST	☐	☐
Ind. ☐				PST	☐	☐

Other Equipment	Description of Equipment	Monthly Rental $	GST ☐ PST ☐

Model Number (Commercial & Industrial Equipment Only)	Original Date of Installation	Year 20	Month	Day	Min. # Bills

ISSUE

Qty	Stock Number	Make	Mfg Code	Serial Number	Account Number

"(hereinafter called the Appliance) from the date hereof, for a monthly rental of $____ (plus applicable sales taxes), which monthly rental amount shall be subject to increase by NRG on at least thirty (30) days prior written notice and subject to the Conditions on the reverse side hereof."

Natural Resource Gas (hereinafter called NRG) leases to the Customer and the Customer rents from NRG the following:

Equipment	Water Heater Size	Description of Equipment other than Water Heater	Monthly Rental $	TAX	Yes	No
Res. ☐						
Comm. ☐				GST	☐	☐
Ind. ☐				PST	☐	☐

Removal Date - Year 20	Month	Day	Original Installation Date - Year 20	Month	Day	Storeroom	Original Contract #

RETURN

Qty	Stock Number	Make	Mfg Code	Serial Number	Account Number

☐ Scrapped ☐ In Inventory

ALL CONDITIONS OF RENTAL AGREEMENT ON REVERSE SIDE

Executed in duplicate this _____ day of ________________ 20_____

Customer Signature

Sales Department Signature

NRG not responsible for any damages resulting from tank leakage.

I hereby consent to the supply of service and installation of the equipment in the above premises, owned by me and agree to the conditions set forth herein. Any equipment of the Owner's removed by NRG in accordance with this authorization shall be left by NRG in the said premises and NRG shall have no further responsibility with respect to same.

Owner's Signature

Owner's Address

CONDITIONS OF RENTAL AGREEMENT

1. The CUSTOMER agrees to permit and keep the Appliance at the above address or at such other address as NRG may agree to in writing. The CUSTOMER agrees to protect the Appliance from any lien or encumbrance of any nature whatsoever and the CUSTOMER agrees not to sublet or assign his interest hereunder or part with possession of the Appliance without the written consent of NRG. The CUSTOMER shall supply adequately sized and properly charged water conditioning equipment, as specified by NRG. In the event the CUSTOMER fails to supply and maintain adequately sized equipment, the CUSTOMER shall reimburse NRG for all costs incurred as a result of such failure. The CUSTOMER further agrees to keep the Appliance insured for the full insurable value thereof. EXCEPT AS SPECIFICALLY PROVIDED HEREIN THE APPLIANCE SHALL BE OPERATED AT THE RISK OF THE CUSTOMER AND CUSTOMER AGREES TO INDEMNIFY AND SAVE HARMLESS NRG FROM ANY AND ALL CLAIMS AND DAMAGES HOWSOEVER CAUSED ARISING OUT OF THE USE OR THE INSTALLATION OF THE APPLIANCE.

2. Ownership of the Appliance shall at all times remain in NRG.

3. NRG shall maintain and repair the Appliance at its own expense provided that the CUSTOMER will indemnify NRG from any such costs or expenses arising as a result of damage to or destruction of the Appliance from any cause, reasonable wear and tear excepted.

4. If the CUSTOMER discontinues using gas supplied by NRG or fails to perform or observe any of the conditions herein, NRG may forthwith terminate this agreement and without any previous notice or demand or process of law enter the premises wherein the Appliance is situated to repossess the same. If the Appliance is removed by NRG as aforesaid, NRG shall not be liable for any damages resulting from such removal. If the CUSTOMER defaults within twelve months from the installation date, then in addition to any other rights NRG may have, the rental for the remaining months shall, at NRG's option, be due and payable immediately.

5. It is agreed by the CUSTOMER and NRG that the Appliance shall remain personalty.

6. Time is of the essence.

7. The terms of this Agreement constitute the entire Agreement between the parties and, except the monthly rental amount which is subject to increase by NRG, no modification to this Agreement shall be made except in writing signed by both parties.

8. Some of the information contained in this application constitutes "personal information" and is thereby covered under Federal privacy legislation. NRG obtains this information in order to bill for the rental of the products identified in this agreement, repairs and service to the equipment and for collections of arrears of amounts owing under this agreement. NRG does not share this information with third parties with the exception of consultants, professional advisors and regulatory bodies. All of these parties are bound by their own privacy obligations which restricts further dissemination of such information.

NRG

Natural Resource Gas Limited

P.O. Box 307, 39 Beech Street East
Aylmer, ON N5H 2S1

Phone: 519-773-5321

SERVICE POLICY

Regular Hours Calls

See section 2.4 for rates to be charged.

All service calls to be done on a time and material basis except for the following:

1. New equipment sold by NRG, no charge for the first year except for parts that are not guaranteed for one year.
2. No charge for service of any kind on any call due to failure of Company equipment.
3. After hours calls (see section 2.4 for rates).
4. All charges to be collected at time of call, unless otherwise authorized.

MISCELLANEOUS CHARGES

1. **Returned Cheques**

Account Closed Cannot Trace Funds Not Cleared More Than One Signature Required No Chequing Privileges Not Sufficient Funds Present Again Refer to Drawer Signature Required Signature Irregular Body & Figures Differ	$ 20.00/each + taxes

2. **Lawyer's Letters**

Reply to request for account information	$ 20.00 + taxes

NATURAL RESOURCE GAS LIMITED

SCHEDULE OF SERVICE CHARGES

	Fiscal 2006	Fiscal 2007	Fiscal 2008	Fiscal 2009	Bridge 2010	Test Year 2011
Rental Water Heaters						
(Monthly Rental Rates)						
30 gallon	$6.85-7.00	$6.85-7.00	$6.85-7.00	$6.85-7.00	$8.85-9.55	$8.85-10.55
40 gallon	$7.25-9.70	$7.25-9.70	$7.25-9.70	$7.25-9.70	$9.25-10.75	$9.25-11.75
40 gallon PV	$12.80-15.50	$12.80-15.50	$12.80-15.50	$12.80-15.50	$14.80-19.00	$14.80-20.00
50 gallon	$8.40-12.00	$8.40-12.00	$8.40-12.00	$8.40-12.00	$11.00-12.50	$11.00-13.50
50 gallon PV	$13.90-17.00	$13.90-17.00	$13.90-17.00	$13.90-17.00	$16.50-21.00	$16.50-22.00
60 gallon	$9.50-12.25	$9.50-12.25	$9.50-12.25	$9.50-12.25	$11.50-15.00	$11.50-16.00
60 gallon PV	$15.30-22.00	$15.30-22.00	$15.30-22.00	$15.30-22.00	$17.50-22.00	$17.50-23.00
Tankless	n/a	n/a	n/a	$34.50	$34.50	$34.50-35.50
Connect/Transfer Charge	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Reply to Lawyer's Letter	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Disconnection Charge	$78.00	$78.00	$78.00	$78.00	$78.00	$78.00
Reconnection Charge	$78.00	$78.00	$78.00	$78.00	$78.00	$78.00
NSF Charge	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Contract Work			On a Quoted Basis			
Merchandise			Parts Marked UP 30 - 50%			
Customer Service Work - Regular Hours						
Minimum Charge - up to 30 minutes	$46.20	$48.50	$48.50	$48.50	n/a	n/a
Minimum Charge - up to 60 minutes	$63.80	$67.00	$67.00	$67.00	$67.00	$90.00
Each additional half hour or part thereof	$28.60	$30.00	$30.00	$30.00	$30.00	n/a
Each additional hour or part thereof	n/a	n/a	n/a	n/a	n/a	$90.00
Customer Service Work - After Hours						
Minimum Charge - up to 30 minutes	$81.95	$86.05	$86.05	$86.05	n/a	n/a
Minimum Charge - up to 60 minutes	$105.60	$110.90	$110.90	$110.90	$110.90	$115.00
Each additional half hour or part thereof	$52.80	$58.10	$58.10	$58.10	$58.10	n/a
Each additional hour or part thereof	n/a	n/a	n/a	n/a	n/a	$95.00

NATURAL RESOURCE GAS LIMITED

Financial Statements

Year Ended September 30, 2013

NATURAL RESOURCE GAS LIMITED
Index to Financial Statements
Year Ended September 30, 2013

NPT+ LLP
CHARTERED ACCOUNTANTS
Adding value. Finding balance.

P: 519-432-5534
F: 519-432-6544
300-633 COLBORNE ST.
LONDON, ONTARIO N6B 2V3
www.nptca.com

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheet as at September 30, 2013 and the statements of income, deficit and cash flow for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

The Company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian accounting standards for private enterprises require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet unless the shares were issued under certain income tax planning arrangements. The Company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities as at September 30, 2013 would increase by $13,461,418 and share capital would decrease by $13,461,418.

(continues)

Qualified Opinion

In our opinion, except that the Class C shares of the Company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 2013 and the results of its operations and its cash flows for then ended in accordance with Canadian accounting standards for private enterprises.

NPT LLP

London, Canada
January 17, 2014

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED
Balance Sheet
September 30, 2013

	2013	2012
ASSETS		
CURRENT		
Cash	$ **1,298,408**	$ 123,362
Accounts receivable *(Notes 8, 12, 13)*	**817,898**	1,347,291
Inventory *(Note 4)*	**102,929**	129,551
Income taxes recoverable	**-**	11,010
Taxes other than income taxes recoverable	**27,306**	-
Prepaid expenses	**47,045**	80,385
	2,293,586	1,691,599
Property, plant and equipment *(Note 5)*	**12,901,554**	13,221,322
Franchises and consents *(Note 6)*	**357,424**	28,246
	$ **15,552,564**	$ 14,941,167
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT		
Accounts payable and accrued liabilities *(Notes 8, 11)*	$ **1,984,122**	$ 1,559,228
Income taxes payable	**198,247**	-
Customer deposits	**136,555**	144,762
Taxes other than income taxes payable	**-**	12,779
Deferred revenue	**71,416**	63,477
Future income taxes	**241,000**	395,000
Term notes payable *(Note 9)*	**6,063,799**	6,409,603
	8,695,139	8,584,849
Future income taxes	**200,000**	162,000
	8,895,139	8,746,849
SHAREHOLDERS' EQUITY		
Share capital *(Note 10)*	**13,461,439**	13,461,439
Deficit	**(6,804,014)**	(7,267,121)
	6,657,425	6,194,318
	$ **15,552,564**	$ 14,941,167

ON BEHALF OF THE BOARD

____________________ *Director*

____________________ *Director*

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statement of Deficit
Year Ended September 30, 2013

	2013	2012
DEFICIT - BEGINNING OF YEAR	**$ (7,267,121)**	$ (7,971,936)
Net income for the year	**463,107**	704,815
DEFICIT - END OF YEAR	**$ (6,804,014)**	$ (7,267,121)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year Ended September 30, 2013

	2013	2012
Gas commodity revenue	$ 4,336,729	$ 3,991,342
Gas commodity cost	(4,328,466)	(3,984,035)
Gross margin on commodity	8,263	7,307
Distribution revenue	5,982,779	5,450,436
Distribution costs	(934,936)	(861,691)
Gross margin on distribution	5,047,843	4,588,745
Other sales	941,232	971,847
Labour and materials costs related to other sales	(135,143)	(196,769)
Amortization related to other sales	(178,462)	(179,622)
Gross margin on other sales	627,627	595,456
Other revenue	134,108	219,408
TOTAL GROSS MARGIN	5,817,841	5,410,916
OPERATING EXPENSES *(Schedule 1)*	5,185,734	4,551,101
INCOME FROM OPERATIONS	632,107	859,815
INCOME BEFORE PROVISION FOR INCOME TAXES	632,107	859,815
INCOME TAXES		
Current	285,000	97,000
Future	(116,000)	58,000
	169,000	155,000
NET INCOME FOR THE YEAR	$ 463,107	$ 704,815

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flow

Year Ended September 30, 2013

	2013	2012
OPERATING ACTIVITIES		
Net income for the year	$ **463,107**	$ 704,815
Items not affecting cash:		
Amortization of property, plant and equipment	**1,048,961**	1,030,616
Amortization of franchises and consents	**44,091**	39,399
Future income taxes	**(116,000)**	58,000
	1,440,159	1,832,830
Changes in non-cash working capital:		
Accounts receivable	**(60,162)**	38,784
Other current assets	**589,555**	(304,486)
Inventory	**26,622**	(12,007)
Prepaid expenses	**33,340**	14,812
Accounts payable and accrued liabilities	**424,897**	(596,387)
Income taxes payable / recoverable	**209,257**	(102,070)
Taxes other than income taxes payable/recoverable	**(40,085)**	239,816
Deferred revenue	**7,939**	(77,522)
Customer deposits	**(8,207)**	(4,136)
	1,183,156	(803,196)
Cash flow from operating activities	**2,623,315**	1,029,634
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(736,724)**	(941,751)
Proceeds on disposal of property, plant and equipment	**7,529**	13,183
Purchase of intangible assets	**(373,270)**	-
Cash flow used by investing activities	**(1,102,465)**	(928,568)
FINANCING ACTIVITY		
Repayments of term notes payable	**(345,804)**	(345,804)
INCREASE (DECREASE) IN CASH	**1,175,046**	(244,738)
Cash - beginning of year	**123,362**	368,100
CASH - END OF YEAR	$ **1,298,408**	$ 123,362

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

The Company operates as a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

2. BASIS OF PRESENTATION

The financial statements were prepared in accordance with Canadian accounting standards for private enterprises (ASPE). ASPE are part of Canadian generally accepted accounting principles (GAAP).

Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Revenue recognition

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet (included in accounts receivable or accounts payable and accrued liabilities) pending disposition by a decision of the OEB.

Rental revenue is recognized as income in the month earned. Revenue on other sales not subject to rate regulations are recognized when goods have been delivered or services have been performed.

Cash

Cash consists of cash on hand and bank account balances, with adjustments for outstanding cheques or deposits at year-end.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Inventory

Inventory consists of rental products and materials used for the service of existing gas pipelines and the addition of new gas pipelines. Inventory is valued at the lower of cost and net realizable value with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Franchises and consents

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful. These costs are amortized on a straight line basis over the term of the franchise.

These assets are tested for an impairment in value when events or circumstances indicate that an asset might be impaired. The assets are tested for impairment by comparing their carrying value to estimates of their fair value. Fair value is based on estimates of discounted future cash flows or other valuation methods. When the fair value is determined to be less than carrying value, the resulting impairment is reported in the income statement.

Deferred charges

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Property, plant and equipment

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment that is subject to rate regulation, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization.

For disposals of major property, plant and equipment and for those assets not subject to rate regulation, gains or losses are included in current earnings.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2013.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Amortization

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. Property, plant and equipment are amortized at the following rates and methods listed below:

Buildings	2%	straight-line method
Machinery and equipment	6% to 9%	declining balance method
Automotive equipment	17%	straight-line method
Computer equipment	33%	declining balance method
Computer software	20%	declining balance method
Furniture and fixtures	7%	straight-line method
Meters and regulators	3% to 4%	straight-line method
Pipeline installations	3% to 5%	straight-line method

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year, and the rates were reaffirmed as part of the 2011 Cost of Service Rate filing. Any such changes in estimate are applied on a prospective basis.

Future income taxes

Income taxes are reported using the future income taxes method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

Gas commodity costs and gas transportation costs

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

(continues)

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Financial instruments policy

Financial instruments are recorded at fair value when acquired or issued. In subsequent periods, financial assets with actively traded markets are reported at fair value, with any unrealized gains and losses reported in income. All other financial instruments are reported at amortized cost, and tested for impairment at each reporting date.

Transaction costs on the acquisition, sale, or issue of financial instruments are expensed when incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their original issuance or assumption.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian ASPE requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Such estimates are periodically reviewed and any adjustments necessary are reported in earnings in the period in which they become known. Actual results could differ from these estimates.

4. INVENTORY

	2013	2012
Materials for use in pipeline maintenance	$ **81,993**	$ 104,006
Rental products	**20,936**	25,545
	$ **102,929**	$ 129,551

During the year, inventories in the amount of $57,584 (2012 - $99,354) were recognized as an expense.

5. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated amortization	**2013 Net book value**	2012 Net book value
Land	$ 71,700	$ -	$ **71,700**	$ 71,700
Buildings	684,089	197,915	**486,174**	499,603
Machinery and equipment	3,083,913	1,593,531	**1,490,382**	1,532,611
Automotive equipment	434,629	369,971	**64,658**	82,423
Computer equipment	403,425	346,962	**56,463**	59,015
Furniture and fixtures	82,205	60,448	**21,757**	24,360
Meters and regulators	3,769,910	2,190,898	**1,579,012**	1,468,199
Pipeline installations	16,143,973	7,012,565	**9,131,408**	9,483,411
	$ 24,673,844	$ 11,772,290	$ **12,901,554**	$ 13,221,322

The Company has completed construction of a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer. The Company entered into a Pipeline Cost Recovery Agreement with the customer, whereby the company and the customer share in the construction cost of the pipeline under defined terms and conditions.

As of September 30, 2013 a final cost reconciliation has not yet been agreed upon between the two parties. While the net cost to the Company of the pipeline constructed cannot be determined with complete accuracy until a cost reconciliation is agreed upon, it is management's opinion that the amount capitalized at September 30, 2013 is a reasonable estimate of the final cost given current information available.

6. FRANCHISES AND CONSENTS

	2013	2012
Franchises and consents	$ **524,363**	$ 151,094
Accumulated amortization	**(166,939)**	(122,848)
	$ **357,424**	$ 28,246

7. OPERATING LINE OF CREDIT

The Company has credit facilities in the amount of $3,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Non-revolving line of credit in the amount of $2,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 8.

8. RELATED PARTY TRANSACTIONS

Included in accounts receivable are amounts receivable from related companies of $14,849 (2012 - $1,347).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $73,076 (2012 - $84,756).

During the year, management fees of $457,020 (2012 - $457,020) were paid to a related company.

During the year, the Company purchased gas in the amount of $856,836 (2012 - $897,006) from a related company.

During the prior year, the Company sold a natural gas well to a related company for $25,000.

During the year, maintenance charges of $6,000 (2012 - $6,000) were charged to a related company.

During the year, the Company paid capital costs of $nil (2012 - $332,754) for the construction of various plastic mains to a related company.

During the year, the Company paid special management fees for regulatory activities of $75,000 (2012 - $nil) to a related company.

During the year, the Company agreed to provide credit facilities to a related party up to a maximum of $2,000,000 with interest charged at 1% per annum on the outstanding balance. The credit facility was utilized during the year, however no balance is outstanding on the facility at September 30, 2013. Interest earned on advances made under the credit facility amount to $13,719.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

9. TERM NOTES PAYABLE

		2013		2012
Bank of Nova Scotia term note payable, maturing on June 30, 2014, interest at bank prime plus 0.25%, repayable in monthly payments of $12,386, due on demand.	$	**2,613,396**	$	2,762,028
Bank of Nova Scotia term note payable, maturing on April 17, 2014, interest at bank prime, repayable in monthly payments of $16,431 plus interest, due on demand.		**3,450,403**		3,647,575
	$	**6,063,799**	$	6,409,603

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 6):

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Postponement of dividends and share redemption payments by the Class C shareholders

e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The term notes payable, the operating line of credit, and the revolving line of credit include the following covenants that the company must meet:

1. maintain a debt service coverage ratio of 1.25:1 or better; and

2. maintain a ratio of debt to tangible net worth of 3.0 or less; and

3. annual capital expenditures of $1.3 million or less; and

At September 30, 2013, the company was in compliance with these covenants.

10. SHARE CAPITAL

Authorized:

Unlimited	Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends
Unlimited	Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution
Unlimited	Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share
Unlimited	Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement
Unlimited	Unlimited number of common shares

		2013	2012
Issued:			
50,000	Class A shares	$ **1**	$ 1
10	Class B shares	**10**	10
134,614	Class C shares	**13,461,418**	13,461,418
10	Class Z shares	**10**	10
		$ **13,461,439**	$ 13,461,439

11. GAS IMBALANCES

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas consumed and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $570,711 (2012 - $750,486) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

12. REGULATORY MATTERS

The Company's distribution rates are approved by the OEB. The Company's commodity rates are approved by the OEB and adjusted on a quarterly basis based on commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB.

One of the Company's franchise agreements with a municipality expired during the prior year. During the year, the OEB issued a Decision and Order which approved a new franchise agreement with the municipality for a period of 20 years, retroactive to the expiry date of the previous agreement. Additionally, certain of the other franchise agreements with various other municipalities expired during the year. The OEB issued interim orders which extended the franchise terms under the old agreement until such time as a new franchise agreement was entered into. Management expects that the new franchise agreements will be substantially similar to the Model Franchise Agreement from the OEB.

The Company has a matter before the OEB relating to the allowable natural gas price it can recover from natural gas purchased from a related party. The OEB is currently seeking additional information prior to making a ruling on this matter.

Accounting principles differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities. The following balances are a direct result of rate regulatory matters:

Included in accounts payable is $370,537 (2012 - $589,555 included in accounts receivable) resulting from the regulated ratemaking process that may not be recorded under ASPE in the absence of rate regulation.

In the absence of rate-regulation, some of the above balances would be recognized in the income statement of the organization. As a result, net income from operations would be increased by $286,452 (2012 - decreased by $247,528).

In the absence of rate-regulation, the Company's current future income tax liability would be lower by $241,000 (2012 - $395,000) as a result of the elimination of the regulatory amounts included in accounts payable and accounts receivable.

13. FINANCIAL INSTRUMENTS

The Company is exposed to various risks through its financial instruments. The following analysis provides information about the Company's risk exposure and concentration. There have been no significant changes to the nature or concentration of these risks from the prior year, unless otherwise stated.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The Company is exposed to credit risk from customers. In order to reduce its credit risk, the Company reviews a new customer's credit history before extending credit and conducts regular reviews of its existing customers' credit performance. The Company has the ability to take security deposits if there are payment issues, and charge interest and penalties on any late payments. The Company has a significant number of customers which minimizes concentration of credit risk.

An allowance for doubtful accounts is established based upon factors surrounding the credit risk of specific accounts, historical trends and other information. The allowance for doubtful accounts was $137,484 at September 30, 2013 (2012 - $109,784).

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk by forecasting its cash needs on a regular basis and seeking additional information based on those forecasts. The Company's objective is to generate sufficient cash from its operations to meet its financial obligations. The Company also maintains available credit facilities as described in note 7 to support the liquidity requirements of the business.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk.

Currency risk

Currency risk is the risk to the company's earnings that arise from fluctuations of foreign exchange rates. The company is not exposed to currency risk as it does not hold financial instruments denominated in a foreign currency.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to interest rate risk primarily through its term notes payable and lines of credit as they bear interest at a fluctuating bank prime rate related interest rate. Additionally, the Company earns interest or is charged interest on its regulatory amounts receivable or amounts payable at the interest rate prescribed by the OEB, which is subject to adjustment on a quarterly basis.

Included in other revenue is interest income of $42,642 (2012 - $69,368) earned on regulatory balances and charged on late payments.

(continues)

13. FINANCIAL INSTRUMENTS *(continued)*

Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market. The Company is exposed to other price risk through its natural gas prices.

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

NATURAL RESOURCE GAS LIMITED

Schedule of Operating Expenses *(Schedule 1)*

Year Ended September 30, 2013

	2013	2012
Salaries and benefits	$ **1,352,119**	$ 1,365,221
Amortization of property, plant and equipment	**870,498**	850,993
Gas commodity costs	**508,585**	-
Property taxes	**471,816**	506,474
Management fees *(Note 8)*	**457,020**	457,020
Ontario Energy Board hearings and regulatory charges	**400,906**	246,479
Insurance	**274,243**	285,902
Office	**196,578**	202,929
Interest on term notes payable	**193,994**	203,096
Repairs and maintenance	**150,576**	148,730
Professional fees	**77,148**	75,292
Vehicle	**61,378**	68,809
Advertising	**59,451**	69,136
Interest expense	**53,092**	54,631
Amortization of franchises and consents	**44,091**	39,399
Bad debts	**29,689**	200
Utilities	**11,043**	9,832
	5,212,227	4,584,143
Equipment expenses capitalized to pipeline installations	**(16,471)**	(22,006)
Amortization capitalized to pipeline installations	**(10,022)**	(11,036)
	$ **5,185,734**	$ 4,551,101

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Financial Statements

Years Ended September 30, 2012 and 2011

NATURAL RESOURCE GAS LIMITED
Index to Financial Statements
Years Ended September 30, 2012 and 2011

NPT+ LLP
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INDEPENDENT AUDITOR'S REPORT

To the Directors of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheets as at September 30, 2012, September 30, 2011 and October 1, 2010, and the statements of income, deficit and cash flows for the years ended September 30, 2012 and September 30, 2011, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our qualified audit opinion.

Basis for Qualified Opinion

The Company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian accounting standards for private enterprises require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet unless the shares were issued under certain income tax planning arrangements. The Company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities as at September 30, 2012, September 30, 2011 and October 1, 2011 would increase by $13,461,418 and share capital would decrease by $13,461,418.

(continues)

Qualified Opinion

In our opinion, except that the Class C shares of the Company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 2012, September 30, 2011 and October 1, 2010 and the results of its operations and its cash flows for the years ended September 30, 2012 and September 30, 2011 in accordance with Canadian accounting standards for private enterprises.

NPT LLP

London, Canada
January 29, 2013

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheets

September 30, 2012 and 2011 and October 1, 2010

	September 30 **2012**	*September 30* 2011	*October 1* 2010
ASSETS			
CURRENT			
Cash	**$ 123,362**	$ 368,100	$ 483,631
Temporary investments	**-**	-	2,579,300
Accounts receivable *(Notes 7, 11, 12)*	**1,347,291**	1,081,589	989,426
Inventory *(Note 3)*	**129,551**	117,544	105,260
Prepaid expenses	**80,385**	95,197	136,252
Income taxes recoverable	**11,010**	-	29,509
Taxes other than income taxes recoverable	**-**	227,037	72,580
Due from related company	**-**	-	350,000
	1,691,599	1,889,467	4,745,958
Property, plant and equipment *(Note 4)*	**13,221,322**	13,323,363	13,518,088
Franchises and consents *(Note 5)*	**28,246**	67,645	163,326
Deferred charges	**-**	-	-
	13,249,568	13,391,008	13,681,414
	$ 14,941,167	$ 15,280,475	$ 18,427,372

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheets

September 30, 2012 and 2011 and October 1, 2010

	September 30 2012	*September 30* 2011	*October 1* 2010
LIABILITIES AND SHAREHOLDERS' EQUITY			
CURRENT			
Accounts payable and accrued liabilities *(Notes 7, 10)*	**$ 1,559,228**	$ 2,155,608	$ 2,001,469
Income taxes payable	**-**	91,060	-
Taxes other than income taxes payable	**12,779**	-	-
Deferred revenue	**63,477**	140,999	191,310
Future income taxes	**395,000**	278,000	303,000
Customer deposits	**144,762**	148,898	168,627
Term notes payable *(Note 8)*	**6,409,603**	6,755,407	10,231,214
	8,584,849	9,569,972	12,895,620
Future income taxes	**162,000**	221,000	286,000
	8,746,849	9,790,972	13,181,620
SHAREHOLDERS' EQUITY			
Share capital *(Note 9)*	**13,461,439**	13,461,439	13,461,439
Deficit	**(7,267,121)**	(7,971,936)	(8,215,687)
	6,194,318	5,489,503	5,245,752
	$ 14,941,167	$ 15,280,475	$ 18,427,372

ON BEHALF OF THE BOARD

_______________________________ *Director*

_______________________________ *Director*

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statements of Deficit
Years Ended September 30, 2012 and 2011

	2012	2011
DEFICIT - BEGINNING OF YEAR	**$ (7,971,936)**	$ (8,215,687)
Net income for the year	**704,815**	243,751
DEFICIT - END OF YEAR	**$ (7,267,121)**	$ (7,971,936)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statements of Income

Years Ended September 30, 2012 and 2011

	2012	2011
Gas commodity revenue	$ 3,991,342	$ 5,206,339
Gas commodity cost	(3,984,035)	(5,181,544)
Gross margin on commodity	7,307	24,795
Distribution revenue	5,450,436	5,690,354
Distribution costs	(861,691)	(893,942)
Gross margin on distribution	4,588,745	4,796,412
Other sales	971,847	1,000,015
Labour and materials costs related to other sales	(196,769)	(224,657)
Amortization related to other sales	(179,622)	(176,022)
Gross margin on other sales	595,456	599,336
Other revenue	219,408	149,056
TOTAL GROSS MARGIN	5,410,916	5,569,599
OPERATING EXPENSES*(Schedule 1)*	4,551,101	4,453,069
INCOME FROM OPERATIONS	859,815	1,116,530
Natural gas exploration expenses	-	(837,780)
INCOME BEFORE PROVISION FOR INCOME TAXES	859,815	278,750
INCOME TAXES		
Current	97,000	125,000
Future	58,000	(90,000)
	155,000	35,000
NET INCOME FOR THE YEAR	$ 704,815	$ 243,750

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED
Statements of Cash Flows
Years Ended September 30, 2012 and 2011

	2012	2011
OPERATING ACTIVITIES		
Net income for the year	$ **704,815**	$ 243,751
Items not affecting cash:		
Amortization of property, plant and equipment	**1,030,616**	1,014,753
Amortization of franchises and consents	**39,399**	97,130
Future income taxes	**58,000**	(90,000)
	1,832,830	1,265,634
Changes in non-cash working capital:		
Accounts receivable	**(265,702)**	(92,163)
Inventory	**(12,007)**	(12,284)
Prepaid expenses	**14,812**	41,055
Accounts payable and accrued liabilities	**(596,387)**	154,141
Income taxes payable / recoverable	**(102,070)**	120,569
Taxes other than income taxes payable/recoverable	**239,816**	(154,457)
Deferred revenue	**(77,522)**	(50,311)
Customer deposits	**(4,136)**	(19,729)
	(803,196)	(13,179)
Cash flow from operating activities	**1,029,634**	1,252,455
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(941,751)**	(820,029)
Proceeds on disposal of property, plant and equipment	**13,183**	-
Additions to franchises and consents	**-**	(1,449)
Repayment from related company	**-**	350,000
Proceeds on disposal of temporary investments	**-**	2,579,300
Cash flow from (used by) investing activities	**(928,568)**	2,107,822
FINANCING ACTIVITY		
Repayments of term notes payable	**(345,804)**	(3,475,808)
DECREASE IN CASH	**(244,738)**	(115,531)
Cash - beginning of year	**368,100**	483,631
CASH - END OF YEAR	$ **123,362**	$ 368,100

See accompanying notes to the financial statements.

1. BASIS OF PRESENTATION

The financial statements were prepared in accordance with Canadian accounting standards for private enterprises (ASPE). ASPE are part of Canadian generally accepted accounting principles (GAAP).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

The Company operates as a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian accounting standards for private enterprises. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under ASPE for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Revenue recognition

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet (included in accounts receivable or accounts payable and accrued liabilities) pending disposition by a decision of the OEB.

Revenue on other sales not subject to rate regulations are recognized when goods have been delivered or services have been performed.

Cash

Cash consists of cash on hand and bank account balances, with adjustments for outstanding cheques or deposits at year-end.

(continues)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Temporary investments

Temporary investments consist of a bank issued Guaranteed Investment Certificate, and is valued at amortized cost.

Inventory

Inventory consists of rental products and materials used for the service of existing gas pipelines and the addition of new gas pipelines. Inventory is valued at the lower of cost and net realizable value with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Franchises and consents

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful. These costs are amortized on a straight line basis over the term of the franchise ranging from 20 to 30 years.

These assets are tested for impairment when events or changes in circumstances indicate that an asset might be impaired. The assets are tested for impairment by comparing their carrying value to estimates of their fair value based on estimates of discounted future cash flows or other valuation methods. When the fair value is determined to be less than carrying value, the resulting impairment is reported in the income statement.

Deferred charges

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

(continues)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Property, plant and equipment

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

For natural gas wells, the successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to exploration and development expense. All other exploration costs, including geographical and geophysical costs and annual lease rentals, are charged to exploration and development expense when incurred. Producing properties and significant unproven properties are assessed annually, or more frequently as economic events dictate, for potential impairment. Any impairment loss is recognized when the carrying value of the asset is not recoverable and exceeds its fair value.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2012.

Amortization

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. All categories are amortized using the straight-line method, except for computer equipment and computer software which are amortized using the declining-balance method, at the following annual rates for the property, plant and equipment categories listed below:

Buildings	2%
Machinery and equipment	6% to 9%
Automotive equipment	17%
Computer equipment	33%
Computer software	20%
Furniture and fixtures	7%
Meters and regulators	3% to 4%
Pipeline installations	3% to 13%

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year, and the rates were reaffirmed as part of the 2011 Cost of Service Rate filing. Any such changes in estimate are applied on a prospective basis.

(continues)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Future income taxes

Income taxes are reported using the future income taxes method, as follows: current income tax expense is the estimated income taxes payable for the current year after any refunds or the use of losses incurred in previous years, and future income taxes reflect:

- the temporary differences between the carrying amounts of assets and liabilities for accounting purposes and the amounts used for tax purposes;
- the benefit of unutilized tax losses that will more likely than not be realized and carried forward to future years to reduce income taxes.

Future income taxes are estimated using the rates enacted by tax law and those substantively enacted for the years in which future income taxes assets are likely to be realized, or future income tax liabilities settled. The effect of a change in tax rates on future income tax assets and liabilities is included in earnings in the period when the change is substantively enacted.

Gas commodity costs and gas transportation costs

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

Financial instruments policy

Financial instruments are recorded at fair value when acquired or issued. In subsequent periods, financial assets with actively traded markets are reported at fair value, with any unrealized gains and losses reported in income. All other financial instruments are reported at amortized cost, and tested for impairment at each reporting date.

Transaction costs on the acquisition, sale, or issue of financial instruments are expensed when incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their original issuance or assumption.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian ASPE requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the period. Such estimates are periodically reviewed and any adjustments necessary are reported in earnings in the period in which they become known. Actual results could differ from these estimates.

(continues)

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Changes in accounting policies - Accounting standards for private enterprises

With regard to the Company's transition from former Canadian GAAP to Canadian ASPE, the Company has made the following elections available under Canadian Institute of Chartered Accountants (CICA) Handbook Section 1500 of Canadian ASPE:

Financial instruments

The Company has applied Handbook Section 3856, "Financial instruments", to the opening balance sheet for the first year presented in the financial statements for the year of adoption of ASPE. Any difference between the recognition and measurement of financial instruments at that date, in accordance with Handbook Section 3856, and the prior year's closing balance sheet is recorded as an adjustment to opening retained earnings at the date of transition to ASPE.

Related party transactions

Handbook Section 3840, "Related party transactions", specifies that certain related party transactions shall be measured at the carrying amount and some at the exchange amount. However, under Handbook Section 1500 of Canadian ASPE, the Company is not required to restate assets or liabilities related to transactions with related parties when the related party transaction occurred prior to the date of transition to ASPE. The Company has used this election.

3. INVENTORY

		2012		2011
Materials for use in pipeline maintenance	**$**	**104,006**	$	94,283
Rental products		**25,545**		23,261
	$	**129,551**	$	117,544

During the year, inventories in the amount of $99,354 (2011 - $147,650) were recognized as an expense.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated amortization	**2012 Net book value**
Land	$ 71,700	$ -	$ **71,700**
Buildings	682,331	182,728	**499,603**
Machinery and equipment	3,056,493	1,523,882	**1,532,611**
Automotive equipment	448,597	366,174	**82,423**
Computer equipment	388,949	329,934	**59,015**
Furniture and fixtures	79,260	54,900	**24,360**
Meters and regulators	3,549,926	2,081,727	**1,468,199**
Pipeline installations	15,889,298	6,405,887	**9,483,411**
	$ 24,166,554	$ 10,945,232	$ **13,221,322**

	Cost	Accumulated amortization	2011 Net book value
Land	$ 71,700	$ -	$ 71,700
Buildings	682,331	167,580	514,751
Machinery and equipment	3,002,508	1,469,910	1,532,598
Automotive equipment	514,994	411,351	103,643
Computer equipment	381,357	312,556	68,801
Furniture and fixtures	69,176	49,550	19,626
Meters and regulators	3,434,157	1,952,570	1,481,587
Pipeline installations	15,340,022	5,809,365	9,530,657
	$ 23,496,245	$ 10,172,882	$ 13,323,363

The company has completed construction of a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer. The company entered into a Pipeline Cost Recovery Agreement with the customer, whereby the company and the customer share in the construction cost of the pipeline under defined terms and conditions.

As of September 30, 2012, a final cost reconciliation has not yet been agreed upon between the two parties. While the net cost to the company of the pipeline constructed cannot be determined with complete accuracy until a cost reconciliation is agreed upon, it is management's opinion that the amount capitalized at September 30, 2012 is a reasonable estimate of the final cost given current information available.

5. FRANCHISES AND CONSENTS

	2012	2011
Franchises and consents	$ **151,094**	$ 420,704
Accumulated amortization	**(122,848)**	(353,059)
	$ **28,246**	$ 67,645

6. OPERATING LINE OF CREDIT

The Company has credit facilities in the amount of $3,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Non-revolving line of credit in the amount of $2,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 8.

7. RELATED PARTY TRANSACTIONS

Included in accounts receivable are amounts receivable from related companies of $1,347 (2011 - $1,130).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $84,756 (2011 - $124,836).

During the year, management fees of $457,020 (2011 - $457,020) were paid to a related company.

During the year, the Company purchased gas in the amount of $897,006 (2011 - $573,743) from a related company.

During the year, the Company sold a natural gas well to a related company for $25,000 (2011 - $nil)

During the year, the Company paid drilling costs and project management fees of $nil (2011 - $411,460) for the drilling of an exploration gas well to related companies.

During the year, maintenance charges of $6,000 (2011 - $6,000) were charged to a related company.

During the year, the Company paid capital costs of $332,754 (2011 - $383,794) for the construction of various plastic mains to a related company.

During the year, the Company agreed to provide credit facilities to a related party up to a maximum of $2,000,000 with interest charged at 3% per annum on the outstanding balance. The credit facility was utilzed during the year, however no balance is outstanding on the facility at September 30, 2012.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

8. TERM NOTES PAYABLE

		2012		2011
Bank of Nova Scotia term note payable, interest at bank prime plus 0.25%, repayable in monthly payments of $12,386, due on demand.	$	**2,762,028**	$	2,910,660
Bank of Nova Scotia term note payable, interest at bank prime, repayable in monthly payments of $16,431 plus interest, due on demand.		**3,647,575**		3,844,747
	$	**6,409,603**	$	6,755,407

Principal repayment terms are approximately:

2013	$	345,804
2014		345,804
2015		345,804
2016		345,804
2017		345,804
Thereafter		4,680,583
	$	6,409,603

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 6):

a) General assignment of book debts

b) General Security Agreement over all of the present and future personal property and undertaking of the company

c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank

d) Postponement of dividends and share redemption payments by the Class C shareholders

e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

The term notes payable, the operating line of credit, and the revolving line of credit include the following covenants that the company must meet:

1. maintain a debt service coverage ratio of 1.25:1 or better; and

2. maintain a ratio of debt to tangible net worth of 3.0 or less; and

3. annual capital expenditures of $1.3 million or less; and

At September 30, 2012, the company was in compliance with these covenants.

9. SHARE CAPITAL

Authorized:

Unlimited	Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends
Unlimited	Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution
Unlimited	Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share
Unlimited	Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement
Unlimited	Unlimited number of common shares

		2012	2011
Issued:			
50,000	Class A shares	$ 1	$ 1
10	Class B shares	10	10
134,614	Class C shares	13,461,418	13,461,418
10	Class Z shares	10	10
		$ 13,461,439	$ 13,461,439

10. GAS IMBALANCES

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $750,486 (2011 - $883,800) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

11. REGULATORY MATTERS

The Company has rates that are approved by the OEB. During a prior year, the company submitted an application for rates for the sale, distribution, transmission and storage of natural gas. As part of this application, the company sought a five year incentive rate mechanism as well. During the prior year, the OEB issued a Decision and Order on this matter, which established the rates which would be in effect retroactively to October 1, 2010 and continuing on until October 1, 2013.

During the year, the company filed an application for its 2012 incentive rate mechanism which would be effective October 1, 2012. The matter is currently before the OEB.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

One of the Company's franchise agreements with a municipality expired during the year. Subsequent to year-end, the OEB issued a Decision and Order which approved a new franchise agreement with the municipality for a period of 20 years, retroactive to the expiry date of the previous agreement. Additionally, certain of the other franchise agreements with various other municipalities expired subsequent to year-end. The OEB issued interim orders which extended the franchise terms under the old agreement until such time as a new franchise agreement was entered into. Management expects that the new franchise agreements will be substantially similar to the Model Franchise Agreement from the OEB.

Finally, the Company has a matter before the OEB relating to the allowable natural gas price it can recover from natural gas purchased from a related party. The OEB is currently seeking additional information prior to making a ruling on this matter. In the opinion of Management, the Company will be successful in recovering the full natural gas price through future natural gas rates. Therefore, the difference between the actual price charged by the related party and the amount currently being allowed by the OEB is included in accounts receivable.

Included in accounts receivable is $589,555 (2011 - $285,969) resulting from the regulated ratemaking process that may not be recorded under ASPE in the absence of rate regulation. The Company estimates that $242,912 of this amount will be recovered / settled in the upcoming year, with the remaining amount to be recovered / settled over the next two to five years.

In the absence of rate-regulation, some of the above balances would be recognized in the income statement of the organization. As a result, net income from operations would be decreased by $247,528 (2011 - $129,340).

In the absence of rate-regulation, the Company's current future income tax liability would be lower by $395,000 (2011- $278,000) as a result of the elimination of the regulatory amounts included in accounts receivable.

12. FINANCIAL INSTRUMENTS

The Company is exposed to various risks through its financial instruments. The following analysis provides information about the Company's risk exposure and concentration. There have been no significant changes to the nature or concentration of these risks from the prior year, unless otherwise stated.

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. The Company is exposed to credit risk from customers. In order to reduce its credit risk, the Company reviews a new customer's credit history before extending credit and conducts regular reviews of its existing customers' credit performance. The Company has the ability to take security deposits if there are payment issues, and charge interest and penalties on any late payments. The Company has a significant number of customers which minimizes concentration of credit risk.

An allowance for doubtful accounts is established based upon factors surrounding the credit risk of specific accounts, historical trends and other information. The allowance for doubtful accounts was $109,784 at September 30, 2012 (2011 - $103,700).

Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk by forecasting its cash needs on a regular basis and seeking additional information based on those forecasts.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: currency risk, interest rate risk and other price risk.

Currency risk

Currency risk is the risk to the company's earnings that arise from fluctuations of foreign exchange rates. The company is not exposed to currency risk.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The Company is exposed to interest rate risk primarily through its term notes payable and lines of credit as they bear interest at a fluctuating bank prime rate related interest rate. Additionally, the Company earns interest or is charged interest on its regulatory amounts receivable or amounts payable at the interest rate prescribed by the OEB, which is subject to adjustment on a quarterly basis.

Included in other revenue is interest income of $69,368 (2011 - $40,550) earned on regulatory balances and charged on late payments.

(continues)

12. FINANCIAL INSTRUMENTS *(continued)*

Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market. The Company is exposed to other price risk through its natural gas prices.

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

13. FIRST TIME ADOPTION OF ACCOUNTING STANDARDS FOR PRIVATE ENTERPRISES

Effective October 1, 2011, the Company adopted the requirements of the Canadian Institute of Chartered Accountants (CICA) Handbook - Accounting, electing to adopt the new accounting framework: ASPE. These are the Company's first financial statements prepared in accordance with ASPE which has been applied retrospectively. The accounting policies set out in the significant accounting policies note have been applied in preparing the financial statements for the year ended September 30, 2012, the comparative information for the year ended September 30, 2011 and in the preparation of the opening ASPE balance sheet at October 1, 2010 (the Company's date of transition).

The Company issued financial statements for the year ended September 30, 2011 using generally accepted accounting principles prescribed by CICA Handbook - Accounting. The adoption of ASPE has no impact on previously reported assets, liabilities and equity of the Company, and accordingly, no adjustments have been recorded in the comparative balance sheet, income statement, statement of retained earnings and the cash flow statement. Certain of the Company's disclosures included in these financial statements reflect the new disclosure requirements of ASPE.

14. COMPARATIVE FIGURES

Some of the comparative figures have been reclassified to conform to the current year's presentation.

NATURAL RESOURCE GAS LIMITED

Schedule of Operating Expenses *(Schedule 1)*

Years Ended September 30, 2012 and 2011

	2012	2011
Salaries and benefits	$ 1,365,221	$ 1,010,296
Amortization of property, plant and equipment	850,993	838,730
Property taxes	506,474	415,184
Management fees *(Note 7)*	457,020	457,020
Insurance	285,902	277,066
Ontario Energy Board hearings and regulatory charges	246,479	278,576
Interest on term notes payable	203,096	392,161
Office	202,929	182,957
Repairs and maintenance	148,730	128,476
Professional fees	75,292	78,814
Advertising	69,136	47,234
Vehicle	68,809	53,463
Interest expense	54,631	77,938
Amortization of franchises and consents	39,399	97,130
Utilities	9,832	11,199
Bad debts	200	32,400
Gas commodity costs not approved by OEB	-	97,000
	4,584,143	4,475,644
Equipment expenses capitalized to pipeline installations	(22,006)	(14,426)
Amortization capitalized to pipeline installations	(11,036)	(8,150)
	$ 4,551,101	$ 4,453,068

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2011

NPT LLP
CHARTERED ACCOUNTANTS
Adding value. Finding balance.

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INDEPENDENT AUDITOR'S REPORT

To the Directors of Natural Resource Gas Limited

We have audited the accompanying financial statements of Natural Resource Gas Limited, which comprise the balance sheet as at September 30, 2011 and the statements of income, deficit and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

(continues)

Basis for Qualified Opinion

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

Qualified Opinion

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2011 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

NPT LLP

London, Canada
January 10, 2012

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2011		2010
Assets				
Current assets:				
Cash	$	**368,100**	$	483,631
Temporary investments		**-**		2,579,300
Accounts receivable (note 5)		**1,308,625**		1,062,006
Inventory		**117,544**		105,260
Prepaid expenses		**92,877**		106,658
Income taxes recoverable		**-**		29,509
Due from related company (note 5)		**-**		350,000
		1,887,146		4,716,364
Property, plant, and equipment (note 1)		**13,323,363**		13,518,088
Other assets:				
Franchises and consents (note 2)		**67,645**		163,326
Deferred finance costs (note 3)		**2,320**		10,579
Deferred charges		**-**		19,015
		69,965		192,920
	$	**15,280,474**	$	18,427,372

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2011		2010
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities (notes 5 and 10)	**$**	**2,155,609**	$	2,001,470
Income taxes payable		**91,060**		-
Deferred revenue		**140,999**		191,310
Future income taxes payable		**278,000**		303,000
Customer deposits		**148,898**		168,627
Term notes payable (note 6)		**6,755,407**		10,231,214
		9,569,973		12,895,621
Future income taxes payable		**221,000**		286,000
		9,790,973		13,181,621
Shareholders' equity:				
Share capital (note 8)		**13,461,439**		13,461,439
Deficit		**(7,971,938)**		(8,215,688)
		5,489,501		5,245,751
	$	**15,280,474**	$	18,427,372

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

		2011		2010
Balance, beginning of year	$	**(8,215,688)**	$	(8,764,981)
Net income for the year		**243,750**		549,293
Balance, end of year	$	**(7,971,938)**	$	(8,215,688)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year ended September 30

		2011		2010
Gas commodity revenue	$	**5,206,339**	$	5,755,731
Gas commodity cost		**5,181,544**		5,719,610
Gross margin on commodity		**24,795**		36,121
Distribution revenue		**5,690,354**		5,335,825
Distribution costs		**893,942**		1,057,081
Gross margin on distribution		**4,796,412**		4,278,744
Other sales		**1,000,014**		1,105,755
Other costs		**400,678**		535,536
Gross margin on other sales		**599,336**		570,219
Other revenue		**149,056**		143,128
Total gross margin		**5,569,599**		5,028,212
Expenses (note 5)		**4,453,069**		4,270,764
Income from operations		**1,116,530**		757,448
Natural gas exploration expenses (note 5)		**(837,780)**		(18,155)
Income before provision for income taxes		**278,750**		739,293
Provision for income taxes:				
Current		**125,000**		36,000
Future		**(90,000)**		154,000
		35,000		190,000
Net income for the year	$	**243,750**	$	549,293

Included in expenses are the following:				
Amortization of deferred financing costs	$	**8,259**	$	10,719
Amortization of deferred charges	$	**19,015**	$	42,650
Amortization of franchises and consents	$	**97,130**	$	96,647
Amortization of property, plant and equipment	$	**1,014,754**	$	1,026,624
Interest on term notes payable	$	**392,161**	$	565,888

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows
Year ended September 30

		2011		2010
Cash flows from operating activities:				
Net income for the year	$	**243,750**	$	549,293
Items not affecting working capital:				
Amortization		**1,139,158**		1,176,640
Decline in value of natural gas well		**-**		18,155
Gain on disposal of property, plant and equipment		**-**		(8,280)
Future income taxes		**(90,000)**		154,000
Changes in non-cash working capital:				
Accounts receivable		**(246,618)**		(276,241)
Inventory		**(12,284)**		38,197
Prepaid expenses		**13,781**		(18,998)
Income taxes recoverable (note 12)		**29,509**		(29,509)
Accounts payable and accrued liabilities		**154,139**		229,288
Income taxes payable (note 12)		**91,060**		(31,532)
Deferred revenue		**(50,311)**		191,310
Customer deposits		**(19,729)**		(241,224)
		1,252,455		1,751,099
Cash flows from investing activities:				
Additions to property, plant, and equipment		**(820,029)**		(519,531)
Proceeds on disposal of property, plant and equipment		**-**		8,800
Additions to franchises and consents		**(1,449)**		(6,197)
Repayment from (advances to) related company		**350,000**		(350,000)
		(471,478)		(866,928)
Cash flows from financing activities:				
Repayments of term notes payable		**(3,475,808)**		(638,963)
Increase (decrease) in cash and cash equivalents during the year		**(2,694,831)**		245,208
Cash and cash equivalents, beginning of year		**3,062,931**		2,817,723
Cash and cash equivalents, end of year	$	**368,100**	$	3,062,931
Represented by:				
Cash	$	**368,100**	$	483,631
Temporary investments		**-**		2,579,300
	$	**368,100**	$	3,062,931

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Temporary investments:

Temporary investments consist of a bank issued Guaranteed Investment Certificate, and is valued at cost which equals fair market value.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Franchises and consents:

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

For natural gas wells, the successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to exploration and development expense. All other exploration costs, including geographical and geophysical costs and annual lease rentals, are charged to exploration and development expense when incurred. Producing properties and significant unproven properties are assessed annually, or more frequently as economic events dictate, for potential impairment. Any impairment loss is recognized when the carrying value of the asset is not recoverable and exceeds its fair value.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2011.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. All categories are amortized using the straight-line method, except for computer equipment and computer software which are amortized using the declining-balance method, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year, and the rates were reaffirmed as part of the 2011 Cost of Service Rate filing. Any such changes in estimate are applied on a prospective basis.

Income taxes:

The liability method of tax allocation is used in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs and gas transportation costs:

Gas commodity costs and gas transportation costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for consideration in future rate adjustments or disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs or gas transportation costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Property, plant, and equipment:

			2011	2010
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
Land	$ 71,700	$ -	$ 71,700	$ 71,700
Buildings	682,331	167,580	514,751	529,898
Furniture and fixtures	69,176	49,550	19,626	24,296
Machinery and equipment	3,002,508	1,469,910	1,532,598	1,557,265
Computer equipment	167,588	155,675	11,913	17,015
Computer software	213,769	156,881	56,888	54,051
Automotive equipment	514,994	411,351	103,643	123,561
Meters and regulators	3,434,157	1,952,570	1,481,587	1,566,507
Pipeline installations	15,340,022	5,809,365	9,530,657	9,573,795
	$ 23,496,245	$ 10,172,882	$ 13,323,363	$ 13,518,088

The company has completed construction of a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer. The company entered into a Pipeline Cost Recovery Agreement with the customer, whereby the company and the customer share in the construction cost of the pipeline under defined terms and conditions.

As of September 30, 2011, a final cost reconciliation has not yet been agreed upon between the two parties. While the net cost to the company of the pipeline constructed cannot be determined with complete accuracy until a cost reconciliation is agreed upon, it is management's opinion that the amount capitalized at September 30, 2011 is a reasonable estimate of the final cost given current information available.

2. Franchises and consents:

	2011	2010
Franchises and consents	$ 420,704	$ 419,254
Less: accumulated amortization	353,059	255,928
	$ 67,645	$ 163,326

3. Deferred finance costs:

		2011		2010
Deferred finance costs	$	**5,800**	$	53,593
Less: accumulated amortization		**3,480**		43,014
	$	**2,320**	$	10,579

4. Operating line of credit:

The company has credit facilities in the amount of $3,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and

b) Non-revolving line of credit in the amount of $2,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 6.

5. Related party transactions:

Due from related company consists of the following:

		2011		2010
Demand promissory note receivable, bearing interest at 3.5% payable monthly	$	-	$	350,000

Included in accounts receivable are amounts receivable from related companies of $1,130 as at September 30, 2011 (2010 - $1,183).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $124,836 as at September 30, 2011 (2010 - $29,101).

During the year, management fees of $457,020 (2010 - $457,020) were paid to a related company.

During the year, the company purchased gas in the amount of $573,743 (2010 - $706,114) from a related company.

During the year, the company paid drilling costs and project management fees of $411,460 (2010 - $nil) for the drilling of an exploration gas well to related companies.

During the year, maintenance charges of $6,000 (2010 - $12,000) were charged to a related company.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

6. Term notes payable:

		2011		2010
Bank of Nova Scotia term note payable, interest at bank prime plus 0.25%, repayable in monthly payments of $12,386, due April 2012	$	**2,910,660**	$	-
Bank of Nova Scotia term note payable, 7.52% interest, repayable in blended monthly installments of $48,201, refinanced during the year	$	-	$	6,027,881
Bank of Nova Scotia term note payable, interest at bank prime, repayable in monthly payments of $16,431 plus interest, due March 2012		**3,844,747**		-
Bank of Nova Scotia term note payable, interest at bank prime, repayable in monthly payments of $43,333 plus interest, refinanced during the year		-		4,203,333
	$	**6,755,407**	$	10,231,214

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 4):

a) General assignment of book debts
b) General Security Agreement over all of the present and future personal property and undertaking of the company
c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank
d) Postponement of dividends and share redemption payments by the Class C shareholders
e) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

7. Capital management:

The Company defines capital as debt and shareholders' equity. As at September 30, 2011, the company had debt consisting of: term notes payable.

The company's objectives in managing capital are to:

a) Ensure financial capacity to meet current obligations is maintained and continue as a going concern;

b) Ensure financial capacity to maintain and expand the distribution pipeline infrastructure of the utility as determined necessary by the company; and

c) Ensure financial capacity to execute strategic plan is maintained.

In order to manage capital, the company regularly identifies and assesses risks that threaten the ability to meet the company's capital management objectives, and determines the appropriate strategy to mitigate these risks.

The Company is subject to externally imposed capital requirements related to the term note payable (note 6). Specifically, the company must meet the following conditions:

a) maintain a ratio of EBITDA (Earnings before interest, taxes, depreciation and amortization) to interest expense plus scheduled principal repayments on term notes payable within the year of 1.25:1 or better;

b) maintain a ratio of current assets to current liabilities (excluding term note payable) of 1:1 or better;

c) maintain a ratio of total debt to tangible net worth of less than 3:1; and

d) ensure annual capital expenditures are less than $1,300,000.

At September 30, 2011, the company was in compliance with the above conditions a), c) and d) and had obtained a written waiver from the bank for fiscal 2011 for condition b).

8. Share capital:

		2011		2010
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	**$**	**1**	$	1
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	13,461,439

9. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $883,800 (2010 - $909,253) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

10. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2007 was a one year Cost of Service Rate filing. The company received the OEB decision dated September 28, 2006 and the rate order was effective September 28, 2006. The company did not make a submission for the fiscal years 2008 through 2010 which left rates unchanged since 2007.

During the prior year, the company submitted an application for rates for the sale, distribution, transmission and storage of natural gas. As part of this application, the company is seeking a five year incentive rate mechanism as well. During the year, the OEB issued a Decision and Order on this matter, which established the rates which would be in effect as of October 1, 2010 and implemented on March 1, 2011.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

11. Financial instruments and risk:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the term notes payable approximates carrying value at September 30, 2011, as the interest rates charged are market-based variable rates.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Interest rate risk:

The term notes payable and the lines of credit (when utilized) bear interest at a fluctuating bank prime related interest rate and, as such, the company is exposed to interest rate risk.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

12. Additional cash flow statement information:

		2011		2010
Interest paid	**$**	**392,161**	$	565,888
Income taxes paid	**$**	**25,586**	$	82,564

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2011 and hence is excluded from the opinion expressed in our auditors' report dated January 10, 2012 to the Directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, are fairly presented in all respects material to those financial statements.

NPT LLP

London, Canada
January 10, 2012

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

		2011	2010
Advertising		$ 10,360	$ 1,587
Automotive and maintenance		181,939	148,371
Bad debts		32,400	-
Bank charges and other interest		430,606	612,648
Capital tax		-	21,180
Consulting fees		37,675	68,220
Donations and community sponsorships		14,912	16,888
Dues and fees		29,416	25,700
Employee benefits		122,813	120,712
Gas commodity costs not approved by OEB		97,000	-
Insurance		277,066	226,872
Legal and audit		41,139	80,718
Management fees - related company		457,020	457,020
Miscellaneous		8,009	11,939
Office		113,974	121,179
Ontario Energy Board hearings and regulatory charges		278,576	26,900
Promotional rebates		18,634	15,955
Property taxes		415,184	404,345
Salaries and wages		887,482	864,821
Telephone		39,565	48,736
Travel and promotion		3,328	1,952
Utilities		11,199	13,543
Amortization -	Automotive equipment	85,489	74,604
	Buildings	15,148	15,148
	Computer equipment	6,054	8,501
	Computer software	14,172	13,515
	Deferred finance costs and charges	27,275	53,369
	Franchises and consents	97,130	96,647
	Furniture and Fixtures	4,669	4,669
	Machinery and equipment	9,709	53,878
	Meters and regulators	124,945	123,488
	Pipeline installations	578,546	560,884
		4,471,434	4,293,989
Equipment expenses capitalized to pipeline installations		(14,426)	(16,953)
Interest expense		4,211	1,527
Amortization capitalized to pipeline installations		(8,150)	(7,799)
		$ 4,453,069	$ 4,270,764

NATURAL RESOURCE GAS LIMITED

FINANCIAL STATEMENTS

SEPTEMBER 30, 2010

NPT LLP
CHARTERED ACCOUNTANTS
Adding value. Finding balance.

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AUDITORS' REPORT

To the Directors of Natural Resource Gas Limited

We have audited the balance sheet of Natural Resource Gas Limited as at September 30, 2010 and the statements of income, deficit, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

The company has issued and outstanding Class C shares with a redemption value of $13,461,418. Canadian generally accepted accounting principles require that the company present and classify shares that are retractable at the option of the shareholder as a liability on the balance sheet. The company has presented these shares as part of Shareholders' equity. If the shares were classified as liabilities, then the total liabilities would increase by $13,461,418 and share capital would decrease by $13,461,418.

In our opinion, except that the Class C shares of the company have been presented as part of Shareholders' equity rather than as a liability, these financial statements present fairly, in all material respects, the financial position of the company as at September 30, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

NPT LLP

London, Canada
December 3, 2010

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2010		2009
Assets				
Current assets:				
Cash	$	**483,631**	$	66,593
Temporary investments (note 2)		**2,579,300**		2,751,130
Accounts receivable (note 7)		**1,062,006**		785,770
Inventory		**105,260**		143,457
Prepaid expenses		**106,658**		87,660
Income taxes recoverable		**29,509**		-
Due from related company (note 7)		**350,000**		-
		4,716,364		3,834,610
Property, plant, and equipment (note 3)		**13,518,088**		14,043,851
Other assets:				
Franchises and consents (note 4)		**163,326**		253,775
Deferred finance costs (note 5)		**10,579**		18,978
Deferred charges (note 6)		**19,015**		63,986
		192,920		336,739
	$	**18,427,372**	$	18,215,200

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Balance Sheet

As at September 30

		2010		2009
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities (note 7 and 12)	$	**2,001,470**	$	1,772,182
Income taxes payable		**-**		31,532
Deferred revenue		**191,310**		-
Future income taxes payable		**303,000**		84,000
Customer deposits		**168,627**		409,851
Term notes payable (note 9)		**10,231,214**		10,870,177
		12,895,621		13,167,742
Future income taxes payable		**286,000**		351,000
		13,181,621		13,518,742
Shareholders' equity:				
Share capital (note 11)		**13,461,439**		13,461,439
Deficit		**(8,215,688)**		(8,764,981)
		5,245,751		4,696,458
	$	**18,427,372**	$	18,215,200

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Deficit

Year ended September 30

		2010		2009
Balance, beginning of year , as previously reported	$	**(8,764,981)**	$	(8,810,028)
Prior period adjustment (note 1)		-		332,000
Balance, beginning of year, as restated	$	**(8,764,981)**	$	(9,142,028)
Net income for the year		**549,293**		377,047
Balance, end of year	$	**(8,215,688)**	$	(8,764,981)

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Income

Year ended September 30

	2010	2009
Gas commodity revenue	$ 5,755,731	$ 7,226,938
Gas commodity cost	5,719,610	7,193,028
Gross margin on commodity	36,121	33,910
Distribution revenue	5,335,825	5,357,493
Distribution costs	1,057,081	970,246
Gross margin on distribution	4,278,744	4,387,247
Other sales	1,105,755	955,610
Other costs	535,536	486,167
Gross margin on other sales	570,219	469,443
Other revenue	143,128	132,556
Total gross margin	5,028,212	5,023,156
Expenses	4,270,764	4,315,497
Income from operations	757,448	707,659
Decline in value of natural gas well	(18,155)	(177,612)
Income before provision for income taxes	739,293	530,047
Provision for income taxes:		
Current	36,000	50,000
Future	154,000	103,000
	190,000	153,000
Net income for the year	$ 549,293	$ 377,047

	2010	2009
Included in expenses are the following:		
Amortization of deferred financing costs	$ 10,719	$ 10,718
Amortization of deferred charges	$ 42,650	$ 42,650
Amortization of franchises and consents	$ 96,647	$ 65,474
Amortization of property, plant and equipment	$ 1,026,624	$ 913,222
Interest on term notes payable	$ 565,888	$ 603,854

See accompanying notes to the financial statements.

NATURAL RESOURCE GAS LIMITED

Statement of Cash Flows
Year ended September 30

		2010		2009
Cash flows from operating activities:				
Net income for the year	$	**549,293**	$	377,047
Items not affecting working capital:				
Amortization		**1,176,640**		1,032,064
Decline in value of natural gas well		**18,155**		177,612
Gain on disposal of property, plant and equipment		**(8,280)**		-
Future income taxes		**154,000**		103,000
Changes in non-cash working capital:				
Accounts receivable		**(276,241)**		826,977
Inventory		**38,197**		(53,601)
Prepaid expenses		**(18,998)**		(32,701)
Income taxes recoverable (note 15)		**(29,509)**		60,377
Accounts payable and accrued liabilities		**229,288**		(1,241,351)
Income taxes payable (note 15)		**(31,532)**		31,532
Deferred revenue		**191,310**		(120,193)
Customer deposits		**(241,224)**		(347,214)
		1,751,099		813,549
Cash flows from investing activities:				
Additions to property, plant, and equipment		**(519,531)**		(1,054,078)
Proceeds on disposal of property, plant and equipment		**8,800**		-
Additions to franchises and consents		**(6,197)**		(221,990)
Additions to deferred charges		**-**		(5,800)
Advances to related company (net)		**(350,000)**		(302,758)
		(866,928)		(1,584,626)
Cash flows from financing activities:				
Proceeds on issuance of term note payable		**-**		5,200,000
Advances from (repayments of) line of credit		**-**		(806,763)
Repayments of term notes payable		**(638,963)**		(587,015)
		(638,963)		3,806,222
Increase in cash and cash equivalents during the year		**245,208**		3,035,145
Cash and cash equivalents, beginning of year		**2,817,723**		(217,422)
Cash and cash equivalents, end of year	$	**3,062,931**	$	2,817,723
Represented by:				
Cash	$	**483,631**	$	66,593
Temporary investments		**2,579,300**		2,751,130
	$	**3,062,931**	$	2,817,723

See accompanying notes to the financial statements.

Summary of significant accounting policies:

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles, the more significant of which are summarized below.

Regulation:

The utility operations of the company is a rate regulated, natural gas distribution utility and operates within a limited area of Southwestern Ontario under franchise agreements that are approved by the Ontario Energy Board (OEB).

The utility operations are subject to regulations under The Ontario Energy Board Act and The Energy Act (Ontario). Revenue rate schedules are approved periodically by the OEB and are designed to permit a fair and reasonable return to the Company on the utility investment. Realization of the allowed rate of return is subject to actual operating conditions experienced during the year.

The Company follows Canadian generally accepted accounting principles. Such accounting principles may differ for regulated entities from those otherwise expected in non-regulated entities. These differences occur when the regulatory agencies render their decisions on the Company's rate applications and generally involve the timing of revenue and expense recognition to ensure that the Company has achieved a proper matching of revenues and expenses, and as a result the Company records assets and liabilities that would not have been recorded under GAAP for non-regulated entities.

In addition to defining certain accounting requirements, the regulatory agencies have jurisdiction over a number of other matters, which include the rates to be charged for the distribution of gas and approval and recovery of costs for major construction and operations.

Temporary investments:

Temporary investments consist of a bank issued Guaranteed Investment Certificate, and is valued at cost which equals fair market value.

Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on a first-in, first-out basis. Net realizable value is defined as replacement cost.

Deferred charges:

Certain costs, required or permitted by the OEB, have been deferred for recovery from future revenues. The period of recovery for these deferrals has been or will be determined by decisions of the OEB, and will determine the classification of these charges in the financial statements.

Franchises and consents:

Costs associated with acquiring municipal franchises and other consents are capitalized when incurred, if the franchise application is successful.

Property, plant, and equipment:

Property, plant and equipment is recorded at cost, including associated labour and overhead costs. Expenditures which substantially increase the useful life of existing pipeline installations and additions to the pipeline are capitalized. Such expenditures include material, labour and overhead. Maintenance and repairs which do not extend the useful life of pipeline installations are charged to income.

Pursuant to the regulations of the OEB on the disposal of property, plant, and equipment, excluding major disposals, the company transfers the original cost of the retired assets, plus any related removal costs and net of any proceeds on disposition, to accumulated amortization. Proceeds from disposition are credited to accumulated amortization. This effectively credits gains, or charges losses on disposition to accumulated amortization. For major disposals, gains or losses are included in current earnings.

For natural gas wells, the successful efforts method is used to account for oil and gas exploration and development costs. Under this method, acquisition costs of oil and gas properties and costs of drilling and equipping development wells are capitalized. Costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to exploration and development expense. All other exploration costs, including geographical and geophysical costs and annual lease rentals, are charged to exploration and development expense when incurred. Producing properties and significant unproven properties are assessed annually, or more frequently as economic events dictate, for potential impairment. Any impairment loss is recognized when the carrying value of the asset is not recoverable and exceeds its fair value.

The company has reviewed its long-lived assets and determined there exists no asset retirement obligation as of September 30, 2010.

Amortization:

Pursuant to the periodic review and approval by the OEB of amortization rates, amortization is calculated on the total gross cost of each asset category at the end of the year, rather than on an asset specific basis. All categories are amortized using the straight-line method, except for computer equipment and computer software which are amortized using the declining-balance method, at the following annual rates for the property, plant and equipment categories listed below:

Automotive equipment	17 %
Buildings	2 %
Computer equipment	33 %
Computer software	20 %
Furniture and fixtures	7 %
Machinery and equipment	6 % to 9 %
Meters and regulators	3 % to 4 %
Pipeline installations	3 % to 13 %

Amortization of deferred finance costs (related to the issue of debt) is calculated at the annual rate of 20% using the straight-line method over the life of the related debt issuance.

Amortization of franchises and consents is calculated using the straight-line method over the term of the applicable franchise and consent.

Pursuant to the approval of the OEB, the company changes its amortization rates for the various categories of property, plant and equipment as well as for franchises and consents based upon OEB Rate Case filings. The last change was made at the start of the fiscal 2005 year, and the rates were reaffirmed as part of the 2007 Cost of Service Rate filing. Any such changes in estimate are applied on a prospective basis.

Income taxes:

The liability method of tax allocation is used in accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and measured using the substantially enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Revenue recognition:

The Company recognizes revenues when gas has been delivered or services have been performed. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

A significant portion of the Company's operations are subject to regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner consistent with the underlying rate setting mechanism as mandated by the OEB. This may give rise to regulatory deferral accounts on the balance sheet pending disposition by a decision of the OEB.

Gas commodity costs:

Gas commodity costs are recorded using prices approved by the OEB in the determination of customers sales rates. Differences between the OEB approved reference prices and those costs actually incurred are deferred in accounts receivable or accounts payable for future disposition subject to the approval of the OEB, usually within a maximum timeframe of the next fiscal year. In a non-regulated environment periodic variances between gas commodity sales rates and costs would be reported through the income statement annually without the use of deferral accounts.

Use of estimates:

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

1. Accounting policy change:

Effective October 1, 2009, the company adopted changes to Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, "Income Taxes", applicable to rate-regulated enterprises. The section has been amended to include the requirement for rate-regulated enterprises to recognize future income tax assets or liabilities in accordance with the asset and liability method, rather than the taxes payable method as the company is currently using, and is effective for year end beginning on or after January 1, 2009.

The adoption of this new recommendation resulted in the recognition of $332,000 of previously unrecognized future income tax liabilities and an increase in the deficit by the same amount as at October 1, 2008, the date of retroactive adoption of this section.

2. Temporary investments:

		2010		2009
Cashable GICs, with interest rates ranging from 0.35% to 0.59%	$	**766,238**	$	2,751,130
Non-redeemable GIC, earning interest at 1.03%, maturing November 30, 2010		**1,813,062**		-
	$	**2,579,300**	$	2,751,130

3. Property, plant, and equipment:

			2010	2009
	Cost	**Accumulated Amortization**	**Net Book Value**	Net Book Value
Land	**$ 71,700**	**$ -**	**$ 71,700**	$ 71,700
Buildings	**682,331**	**152,433**	**529,898**	545,046
Furniture and fixtures	**69,176**	**44,880**	**24,296**	28,965
Machinery and equipment	**2,933,376**	**1,376,111**	**1,557,265**	1,579,330
Computer equipment	**166,636**	**149,621**	**17,015**	20,293
Computer software	**196,760**	**142,709**	**54,051**	46,461
Automotive equipment	**449,423**	**325,862**	**123,561**	184,090
Meters and regulators	**3,394,132**	**1,827,625**	**1,566,507**	1,570,637
Pipeline installations	**14,804,617**	**5,230,822**	**9,573,795**	9,997,329
	$ 22,768,151	**$ 9,250,063**	**$ 13,518,088**	$ 14,043,851

During the prior year, the company completed construction of a 28.5 kilometre natural gas pipeline between London and Aylmer to service a new customer. The company entered into a Pipeline Cost Recovery Agreement with the customer, whereby the company and the customer share in the construction cost of the pipeline under defined terms and conditions.

As of September 30, 2010, a final cost reconciliation has not yet been agreed upon between the two parties. While the net cost to the company of the pipeline constructed cannot be determined with complete accuracy until a cost reconciliation is agreed upon, it is management's opinion that the amount capitalized at September 30, 2010 is a reasonable estimate of the final cost given current information available.

4. Franchises and consents:

	2010	2009
Franchises and consents	**$ 419,254**	$ 413,057
Less: accumulated amortization	**255,928**	159,282
	$ 163,326	$ 253,775

NATURAL RESOURCE GAS LIMITED

Notes to the Financial Statements - continued

September 30, 2010

5. Deferred finance costs:

		2010		2009
Deferred finance costs	$	**53,593**	$	53,593
Less: accumulated amortization		**43,014**		34,615
	$	**10,579**	$	18,978

6. Deferred charges:

		2010		2009
Total deferred charges - other assets	$	**213,253**	$	213,253
Less: accumulated amortization		**194,238**		149,267
	$	**19,015**	$	63,986

The company has been given approval by the OEB to recover the above costs already incurred from rate payers over future periods. The remaining balance will be recovered over future years as noted below:

2011	$	19,015

7. Related party transactions:

Due from related company consists of the following:

		2010		2009
Demand promissory note receivable, bearing interest at 3.5% payable monthly	$	**350,000**	$	-

Included in accounts receivable are amounts receivable from related companies of $1,183 as at September 30, 2010 (2009 - $544,657).

Included in accounts payable and accrued liabilities are amounts payable to related companies of $29,101 as at September 30, 2010 (2009 - $99,095).

During the year, management fees of $457,020 (2009 - $457,020) were paid to a related company.

During the year, the company purchased gas in the amount of $706,114 (2009 - $1,508,369).

During the year, maintenance charges of $12,000 (2009 - $12,000) were charged to a related company.

Related companies are companies controlled, directly or indirectly, by trusts, where the beneficiaries of the trusts are common to both trusts, but the trustee or group of trustees which exercise control over any of the related parties are different than the group of trustees of the trust which controls Natural Resource Gas Limited.

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

8. Operating line of credit:

The company has credit facilities in the amount of $2,000,000 which it obtained in conjunction with the term note, consisting of:

a) Operating line of credit in the amount of $1,000,000 with interest at the Bank's Prime Rate on any advances, and
b) Revolving line of credit in the amount of $1,000,000 to be used for financing capital expenditures with interest at the Bank's Prime Rate plus 0.25% on any advances.

The continuation of the above credit facilities is subject to annual review by the Bank. These credit facilities are secured by the security agreement in place as disclosed in note 9.

9. Term notes payable:

		2010		2009
Bank of Nova Scotia term note payable, 7.52% interest, repayable in blended monthly installments of $48,201, due March 2011	$	**6,027,881**	$	6,146,844
Bank of Nova Scotia term note payable, interest at bank prime, repayable in monthly payments of $43,333 plus interest, due October 2017		**4,203,333**		4,723,333
	$	**10,231,214**	$	10,870,177

Although the above loans are due on demand, the company expects to make installments as per the amortization schedule that forms part of the loan agreement. The aggregate amount of principal payments required in each of the next five years to meet minimum retirement provisions is as follows:

2011	$	6,547,881
2012		520,000
2013		520,000
2014		520,000
2015		520,000
Thereafter		1,603,333
	$	10,231,214

The company has pledged the following as security against the term notes payable, the operating line of credit, and the revolving line of credit (note 6):

a) General assignment of book debts
b) General Security Agreement over all of the present and future personal property and undertaking of the company
c) Security under Section 427 of the Bank Act with appropriate insurance coverage assigned to the Bank
d) Demand Debenture for $15,000,000 secured by a first fixed and floating charge over all assets including, but not limited to, the Certificate of Public Convenience and Necessity and all Municipal Franchise Agreements, with replacement cost fire insurance coverage, loss if any, payable to the Bank as mortgagee.

10. Capital management:

The Company defines capital as debt and shareholders' equity. As at September 30, 2010, the company had debt consisting of: term notes payable.

The company's objectives in managing capital are to:

a) Ensure financial capacity to meet current obligations is maintained and continue as a going concern;
b) Ensure financial capacity to maintain and expand the distribution pipeline infrastructure of the utility as determined necessary by the company; and
c) Ensure financial capacity to execute strategic plan is maintained.

In order to manage capital, the company regularly identifies and assesses risks that threaten the ability to meet the company's capital management objectives, and determines the appropriate strategy to mitigate these risks.

The Company is subject to externally imposed capital requirements related to the term note payable (note 8). Specifically, the company must meet the following conditions:

a) maintain a ratio of EBITDA (Earnings before interest, taxes, depreciation and amortization) to interest expense plus current portion of long term debt of 1.25:1 or better;
b) maintain a ratio of current assets to current liabilities (excluding term note payable) of 1:1 or better; and
c) maintain a ratio of total debt to tangible net worth of less than 3:1.

At September 30, 2010, the company was not in violation of any of the above conditions.

11. Share capital:

		2010		2009
Authorized:				
Unlimited Class A shares, non-voting, redeemable and retractable at the paid up amount, with non-cumulative dividends				
Unlimited Class B shares, participating, non-voting, with non-cumulative dividends ranking pari passu with common shares on dissolution				
Unlimited Class C shares non-voting, with preferential 7% non-cumulative dividends redeemable and retractable at $100 per share				
Unlimited Class Z shares voting, redeemable and retractable at $1 per share, with no dividend entitlement				
Unlimited number of common shares				
Issued and outstanding:				
Retractable shares:				
50,000 Class A shares	$	**1**	$	1
10 Class B shares		**10**		10
134,614.18 Class C shares		**13,461,418**		13,461,418
10 Class Z shares		**10**		10
	$	**13,461,439**	$	13,461,439

12. Gas imbalances:

The Company, in the normal course of its operations experiences imbalances in the quantity of gas purchased and the quantities of gas sold and provides the gas balancing services to customers. The company records the net liability (or net asset) associated with gas imbalance volumes.

Accounts payable and accrued liabilities include $909,253 (2009 - $899,509) related to gas imbalances. Natural gas volumes owed from the Company are valued at the natural gas reference price as approved by the OEB as of the balance sheet dates.

13. Regulatory matters:

The Company has rates that are approved by the OEB. The fiscal year 2007 was a one year Cost of Service Rate filing. The company received the OEB decision dated September 28, 2006 and the rate order was effective September 28, 2006. The company did not make a submission for the fiscal years 2008 through 2010 which left rates unchanged since 2007.

During the year, the company submitted an application for rates for the sale, distribution, transmission and storage of natural gas, which would be effective beginning October 1, 2010. As part of this application, the company is seeking a five year incentive rate mechanism as well. Subsequent to year end, the OEB issued a Decision and Order on this matter, which established the rates which would be in effect retroactive to October 1, 2010.

Rates for the sale of gas commodity are adjusted quarterly to reflect updated commodity price forecasts. The difference between the approved and the actual cost of gas incurred in the current period is deferred for future recovery subject to approval by the OEB. These differences are directly flowed through to customers and, therefore, no rate of return is earned on the deferred balances. The OEB's approval for recovery of these gas purchase costs primarily considers the prudence of costs incurred.

14. Financial instruments and risk:

The carrying values of the company's financial current assets and liabilities, including cash, accounts receivable, and accounts payable and accrued liabilities approximate their values due to their short-term maturity.

The fair value of the term notes payable is estimated using a discounted cash flow calculation that uses market interest rates currently charged for similar debt instruments at September 30, 2010 to expected maturity dates. Based on the above calculation, the fair value of the term notes payable approximates carrying value at September 30, 2010.

Natural gas prices:

The Company has entered into several material contracts for the supply of natural gas. The Company employs established policies and procedures in order to manage the risk associated with the market fluctuations of natural gas prices. The Company, through the rate regulations imposed by the OEB, is effectively allowed to fully recover its costs, reasonably incurred, and as such the ratepayers, and not the Company, are ultimately exposed to the risk of these market fluctuations.

Interest rate risk:

One of the term notes payable bears a fixed interest rate and, as such, the company is exposed to the interest rate risk of having a fixed rate, but has the security of a fixed rate for operational management purposes.

The other term note payable and the line of credit (when utilized) bears interest at a fluctuating bank prime related interest rate and, as such, the company is exposed to interest rate risk.

Credit risk:

Credit risk arises from the potential that a trade customer will fail to pay its account. The company is exposed to credit risk from its customers. However, the company has a large number of diverse customers, which minimizes concentration of credit risk.

15. Additional cash flow statement information:

		2010		2009
Interest paid	$	**565,888**	$	603,854
Income taxes paid (recoveries received)	$	**82,564**	$	(5,785)

ADDITIONAL COMMENTS OF AUDITORS

The accompanying schedule of expenses is presented as supplementary information only. In this respect, it does not form part of the financial statements of Natural Resource Gas Limited for the year ended September 30, 2010 and hence is excluded from the opinion expressed in our auditors' report dated December 03, 2010 to the Directors on such financial statements. The information in this schedule has been subject to audit procedures only to the extent necessary to express an opinion on the financial statements of the company and, in our opinion, are fairly presented in all respects material to those financial statements.

NPT LLP

London, Canada
December 3, 2010

NPT LLP
Chartered Accountants
Licensed Public Accountants

NATURAL RESOURCE GAS LIMITED

Unaudited Schedule of Expenses

Year ended September 30

		2010	2009
Advertising		$ 1,587	$ 9,873
Automotive and maintenance		148,371	195,208
Bad debts		-	51,982
Bank charges and other interest		612,648	626,316
Capital tax		21,180	36,180
Consulting fees		68,220	55,332
Donations and community sponsorships		16,888	13,953
Dues and fees		25,700	19,424
Employee benefits		120,712	148,883
Insurance		226,872	197,396
Legal and audit		80,718	63,049
Management fees - related company		457,020	457,020
Miscellaneous		11,939	15,324
Office		121,179	154,293
Ontario Energy Board hearings		26,900	32,211
Promotional rebates		15,955	14,437
Property taxes		404,345	390,404
Salaries and wages		864,821	923,983
Telephone		48,736	59,776
Travel and promotion		1,952	3,371
Utilities		13,543	12,658
Amortization -	Automotive equipment	74,604	86,566
	Buildings	15,148	15,148
	Computer equipment	8,501	10,145
	Computer software	13,515	11,615
	Deferred finance costs and charges	53,369	49,814
	Franchises and consents	96,647	69,028
	Furniture and Fixtures	4,669	4,669
	Machinery and equipment	53,878	52,974
	Meters and regulators	123,488	119,159
	Pipeline installations	560,884	447,341
		4,293,989	4,347,532
Equipment expenses capitalized to pipeline installations		(16,953)	(17,956)
Interest expense (income)		1,527	(6,661)
Amortization capitalized to pipeline installations		(7,799)	(7,418)
		$ 4,270,764	$ 4,315,497

SUMMARY OF APPLICATION

Need for Application

NRG seeks an Order(s) from the Board permitting it to charge distribution and transmission rates to its customers from the end of the existing Board Order approving rates (EB-2010-0018), being September 30, 2014, through to September 30, 2016.

At NRG's last rates case (EB-2010-0018), the Board approved:

(a) gas distribution rates for NRG's 2011 Test Year (commencing October 1, 2010 and concluding September 30, 2011); and

(b) an IR Plan for setting distribution rates for the subsequent three years (i.e., for the period through to September 30, 2014).

The Board also approved a transportation rate for local natural gas producers that utilize NRG's distribution system to deliver natural gas to the Union Gas Limited distribution system.

Orders Requested

NRG seeks an Order(s): (a) fixing distribution rates for the next two years (i.e., through to September 30, 2016) based on a continuation of the existing IR Plan for an additional two years; (b) approving existing transportation rates established in EB-2010-0018 (see Exhibit E, Tab 1, Schedule 1); (c) requiring IGPC (NRG's largest customer) to provide updated financial information, as well as updated business plan and security for the undepreciated capital costs (as set out in the Application); and (d) the creation of a deferral account for demand side management programs for NRG's customers.

<u>Rationale for Orders Requested</u>

Requests (a) and (b) – Extension of IR Plan for Distribution Rates; Transportation Rates

NRG's earnings under the existing IR Plan was within the ROE deadband of ± 300 basis points in Fiscal 2011 (9.98%) and Fiscal 2012 (7.16%), and only slightly below the ROE deadband in Fiscal 2013 (6.29%). The IR Plan is therefore operating satisfactorily. On the present information known to NRG, it expects that the IR Plan will continue to operate satisfactorily during the extension period ending on September 30, 2016. See Exhibit C, Tab 1, Schedule 1 for further explanation.

NRG does not foresee any exceptional capital projects or operations/maintenance expenses over the next two years. These facts support the proposal that NRG be granted a two-year extension rather than file a cost-of-service application at this time . See Exhibit C, Tab 5, Schedule 1 for a further explanation.

In the absence of a compelling need to re-base, greatest regulatory efficiency would be achieved by continuing to operate under the existing IR Plan. NRG, its customers, intervenors, and the Board itself will all benefit by allowing NRG to continue on this basis for two years. See Exhibit C, Tab 2, Schedule 1 for further explanation.

There are two other rationale for a two-year extension.

First, in NRG's prior rate case (EB-2010-0018), the Board directed NRG to complete system integrity studies (with the involvement of Board Staff). These studies are not yet complete, but will be finished within the next two years. A full cost-of-service application will be more effective and efficient if the system integrity studies have been completed, so that any major capital expenditures needed to resolve the system integrity issue can be built into NRG's next cost-of-service rate case and IR Plan. See Exhibit C, Tab 3, Schedule 1 for further explanation.

Second, NRG has concerns about IGPC's ability to continue to purchase gas beyond 2016 (when its operating grants are set to expire), as detailed below and elsewhere in this pre-filed evidence. In the absence of better information about IGPC's operations beyond 2016, NRG cannot bring forward a cost-of-service application together with an IR Plan that extends beyond 2016. A two-year extension would permit NRG and the Board to get clarity on IGPC's financial position post-2016 and plan accordingly. See Exhibit C, Tab 4, Schedule 1 and Exhibit D, Tab 1, Schedule 1 for further explanation.

Request (c) – Discrete Orders Regarding IGPC

IGPC is NRG's largest customer. It produces bio fuels from corn grown in the region. It receives two operating grants – the first from Natural Resources Canada under the ecoEnergy for Biofuels Program, and the second from the Ontario Ministry of Agriculture, Food and Rural Affairs. To date, with these grants, IGPC's net income has ranged from \$4.7 million to \$12.4 million (from fiscal 2009 to fiscal 2012). Without the grants, IGPC would operate at a loss ranging from \$14.7 million to \$22.1 million (during that same period). Thus, without the operating grants or some other radical change to its business plan, IGPC will suffer unsustainable losses that threaten IGPC's ability to purchase gas from NRG when the operating grants expire in 2016.

NRG has attempted to understand IGPC's ability to purchase distribution services from NRG post-2016 at its current minimum annual volume of 33,416,618 m^3 (as set out in the Gas

Delivery Contract) in order for NRG to protect itself and its customers from any unexpected cessation of purchases, and resulting stranded asset or decommissioning costs.

In addition to the expected expiration of IGPC's operating grants in 2016, there are two significant milestones affecting NRG and IGPC's relationship during the two-year extension period. The first is the termination of the Gas Delivery Contract between IGPC and NRG on April 30, 2015. The second is the annual expiration of a Delivery Letter of Credit on November 30, 2014 (currently set to be extended by one year). In order to provide NRG with assurances that all undepreciated capital costs of the IGPC Pipeline will be paid (and provision is made for any decommissioning costs if required) if IGPC were to terminate purchase of NRG's distribution services, NRG is requesting that the Board require IGPC to provide certain financial information (as set out in the Application) about IGPC's near-term future viability, IGPC's future plans to purchase services from NRG, and security for the undepreciated capital costs of the IGPC Pipeline.

See Exhibit C, Tab 4, Schedule 1 and Exhibit D, Tab 1, Schedule 1 for further information.

Request (d) – Deferral Account for Demand Side Management Program

To date, NRG has been exempted from having to provide demand side management ("DSM") programs for its customers. By Directive to the Board dated March 26, 2014, the Minister of Energy directed that all rate-regulated gas utilities (including NRG) provide DSM programs to their customers. As a result, NRG is proposing that a deferral account be created to track NRG's DSM costs associated with the new DSM Framework. The deferral account would be cleared at

NRG's next cost-of-service rate case in two years. See Exhibit D, Tab 2, Schedule 1 for further explanation.

EXISTING IR PLAN OPERATING WELL

Explanation of Existing Plan

The existing IR Plan is NRG's first time utilizing an incentive regulation or PBR regime. The IR Plan adjusted NRG's distribution rates in each fiscal year of the period from October 1, 2011 through September 30, 2014 according to the following formula:

$$PCA = I - X + S$$

Where:

PCA = Price Cap Adjustment

I	=	Inflation Factor (actual year-over-year change in the annualized average of four quarters of Statistics Canada's Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP-IPI"), as calculated by the Board and in effect at the time the PCA is made)
X	=	Productivity Factor (same as that utilized by Board for electricity distributor rate adjustments)
S	=	Stretch Factor (0.1% greater than the stretch factor applicable to mid-range electricity distributors)

NRG's existing IR Plan also permits NRG to bring forward, for Board approval, costs for unforeseen events outside of NRG's management control (i.e., Z-factor claims), provided that such claims meet the following three criteria:

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed $50,000 (on an individual event basis) and have a significant influence on the operation of NRG; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that NRG's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

The process for bringing forward Z-factor claims under the IR Plan is as follows:

- NRG must record amounts sought to be claimed as a Z-factor in a separate Z-factor deferral account. Monthly carrying charges would also be recorded (calculated using simple interest applied to the monthly opening balances in the account and recorded in a separate sub-account of this account). The rate of interest is the Board-prescribed rates for deferral and variance accounts for the respective quarterly period published on the Board's website.
- NRG must notify the Board and interveners in EB-2010-0018 of all Z-factor events within six months of the Z-factor event.
- NRG must apply to the Board for recovery of amounts recorded in the Z-factor deferral account, and such application shall include:
  - (a) evidence from NRG demonstrating that the costs incurred meet the three eligibility criteria outlined above;
  - (b) an explanation of the manner in which NRG intends to allocate the incremental revenue requirements to the various customer classes, the rationale for the selected approach and a discussion of the merits of alternative allocation amounts;
  - (c) an explanation as to whether the proposed rate rider to recover the Z-factor amount will apply on a fixed or variable basis or a combination thereof, and the length of the disposition period and rationale for this approach; and
  - (d) a detailed calculation of the rate rider.

NRG's IR Plan also includes a trigger mechanism for a regulatory review if NRG's earnings fall outside an annual ROE deadband of ± 300 basis points, based on NRG's annual audited financial statements (filed with the Board within 60 days of NRG's receipt of such statements). In the event that NRG's financial statements show NRG's earnings falling short of or exceeding NRG's Board-approved ROE by 300 basis points, a review will be carried out by the Board to determine if further action by the Board is warranted. The review would be prospective in nature and could result in modifications to NRG's IR Plan (including its termination or continuation).

IR Plan Going Forward

If this two-year extension Application were approved, the adjustment factors for the PCA on October 1, 2014 would be:

I = 1.7%

X = 0%

S = 0.4%

NRG's Performance Under IR Plan

In the base year and the initial two years of the three year IR Plan, NRG's ROE (as compared to the Board-approved ROE) has been as follows:

	Board-Approved ROE (%)	ROE Deadband (%)	NRG's ROE (%)
Fiscal 2011	9.85	6.85 to 12.85	9.98
Fiscal 2012			7.16
Fiscal 2013			6.29

This puts NRG's earnings within the ROE deadband, with the exception of Fiscal 2013 when it was slightly below the deadband. In Fiscal 2013, the difference between 6.29% and 6.85% is $25,732, which would be classified as an immaterial amount for an electric distributor with the level of distribution revenue the size of NRG. For an electric distributor with distribution revenue of $10 million or less, the materiality threshold is $50,000. This is the same materiality threshold used in NRG's IR Plan for Z-factor claims.

NRG's ROE on its distribution business cannot be calculated using NRG's audited financial statements alone, since the audited financial statements include NRG's ancillary business (hot water tanks). Appropriate adjustments must be made in order to calculate the ROE. The adjusted earnings (noted in the table on the previous page) are at Exhibit C, Tab 1, Schedule 2.

In addition, NRG has not yet made any Z-factor claims, and no amounts are currently recorded in the Z-factor deferral account.

Template for Calculation of ROE on a Deemed Basis

UTILITY NAME: ***NRG***
YEAR END DATE: ***2013***

Please input based on your utility in the grey cells.

				Comments
Regulatory Net Income Calculation:				
Regulated distribution net income		$ 480,424	A	*Distribution component only*
Remove:				
Future/deferred taxes		$ 0	B	*Not applicable*
Non rate regulated items			C	*Not applicable*
Adjustment to interest expense - for deemed debt		$ 191,571	D (=W)	
Adjusted regulated net income		$ 288,853	E = A-B-C-D	

				Comments
Deemed Equity Calculation:				
Rate Base:				
Inventory		$ 44,578	F	*Test year total minus water heater amount*
Working Cash Allowance		$ (52,755)	G	*Test year total minus water heater amount*
Security Deposits		$ (154,167)	H	*Test year total - no amount assigned to water heater*
Total working capital allowance		$ (162,344)	J	
Fixed Assets				
Opening balance - regulated fixed assets (NBV)	$ 11,775,465			
Closing balance - regulated fixed assets (NBV)	$ 11,524,231			*NBV = Net Book Value*
Average regulated fixed assets	$ 11,649,848	$ 11,649,848	K	
Total rate base		**$ 11,487,504**	L = J + K	
Regulated deemed short-term debt	4%	$ 459,500	M	
Regulated deemed long-term debt	56%	$ 6,433,002	N	
Regulated deemed equity	40%	$ 4,595,002	P	
		$ 11,487,504		

				Comments
Regulated Rate of Return on Deemed Equity		**6.29%**	Q = E / P	
ROE% from most recent cost of service application	**last approved EDR**	**9.85%**	R	*Approved ROE from last CoS rate proceeding*
	Allowed	**$452,608**		
Difference - maximum deadband 3%		**-3.56%**	S = Q - R	
	Over/(Under)	**($163,755)**		

				Comments
Interest adjustment on deemed debt:				
Regulated deemed short-term debt - as above	$ 459,500	6.67%		
Regulated deemed long-term debt - as above	$ 6,433,002	93.33%		
	$ 6,892,502	100.00%		
Short-term debt rate	2.07%	0.14%		*Interest rate on short-term debt from last approved CoS rate proceeding*
Long-term debt rate	7.67%	7.16%		*Interest rate on long-term debt from last approved CoS rate proceeding*
Average debt rate		7.30%		
Regulated deemed debt - as above	$ 6,892,502			
Weighted average interest rate	7.30%			
Deemed interest	$ 502,923	T		
Interest expense as per the OEB trial balance	$ 247,086	U		*As per financial statements*
Difference	$ 255,837	V = T - U		
Utility tax rate	25.12%			*Distributor's Board-approved tax rate from the distributor's last rate application(IRM or CoS).*
Tax effect on interest expense	$ (64,266)			
Interest adjustment on deemed debt:	$ 191,571	W		

Template for Calculation of ROE on a Deemed Basis

UTILITY NAME: *NRG*
YEAR END DATE: *2012*

Please input based on your utility in the grey cells.

Regulatory Net Income Calculation:				*Comments*
Regulated distribution net income		$ 523,759	A	*Distribution component only*
Remove:				
Future/deferred taxes		$ 0	B	*Not applicable*
Non rate regulated items			C	*Not applicable*
Adjustment to interest expense - for deemed debt		$ 189,519	D (=W)	
Adjusted regulated net income		$ 334,240	E = A-B-C-D	
Deemed Equity Calculation:				*Comments*
Rate Base:				
Inventory		$ 44,578	F	*Test year total minus water heater amount*
Working Cash Allowance		$ (52,755)	G	*Test year total minus water heater amount*
Security Deposits		$ (154,167)	H	*Test year total - no amount assigned to water heater*
Total working capital allowance		$ (162,344)	J	
Fixed Assets				
Opening balance - regulated fixed assets (NBV)	$ 11,885,162			
Closing balance - regulated fixed assets (NBV)	$ 11,775,465			*NBV = Net Book Value*
Average regulated fixed assets	$ 11,830,314	$ 11,830,314	K	
Total rate base		**$ 11,667,970**	L = J + K	
Regulated deemed short-term debt	4%	$ 466,719	M	
Regulated deemed long-term debt	56%	$ 6,534,063	N	
Regulated deemed equity	40%	$ 4,667,188	P	
		$ 11,667,970		
Regulated Rate of Return on Deemed Equity				*Comments*
		7.16%	Q = E / P	
ROE% from most recent cost of service application	**last approved EDR**	**9.85%**	R	*Approved ROE from last CoS rate proceeding*
	Allowed	**$459,718**		
Difference - maximum deadband 3%		**-2.69%**	S = Q - R	
	Over/(Under)	**($125,478)**		
Interest adjustment on deemed debt:				*Comments*
Regulated deemed short-term debt - as above	$ 466,719	6.67%		
Regulated deemed long-term debt - as above	$ 6,534,063	93.33%		
	$ 7,000,782	100.00%		
Short-term debt rate	2.07%	0.14%		*Interest rate on short-term debt from last approved CoS rate proceeding*
Long-term debt rate	7.67%	7.16%		*Interest rate on long-term debt from last approved CoS rate proceeding*
Average debt rate		7.30%		
Regulated deemed debt - as above	$ 7,000,782			
Weighted average interest rate	7.30%			
Deemed interest	$ 510,824	T		
Interest expense as per the OEB trial balance	$ 257,727	U		*As per financial statements*
Difference	$ 253,097	V = T - U		
Utility tax rate	25.12%			*Distributor's Board-approved tax rate from the distributor's last rate application(IRM or CoS).*
Tax effect on interest expense	$ (63,578)			
Interest adjustment on deemed debt:	$ 189,519	W		

Template for Calculation of ROE on a Deemed Basis

UTILITY NAME: *NRG*
YEAR END DATE: *2011*

Please input based on your utility in the grey cells.

				Comments
Regulatory Net Income Calculation:				*Comments*
Regulated distribution net income		$ 506,266	A	*Distribution component only*
Remove:				
Future/deferred taxes		$ 0	B	*Not applicable*
Non rate regulated items			C	*Not applicable*
Adjustment to interest expense - for deemed debt		$ 35,011	D (=W)	
Adjusted regulated net income		$ 471,256	E = A-B-C-D	
Deemed Equity Calculation:				*Comments*
Rate Base:				
Inventory		$ 44,578	F	*Test year total minus water heater amount*
Working Cash Allowance		$ (52,755)	G	*Test year total minus water heater amount*
Security Deposits		$ (154,167)	H	*Test year total - no amount assigned to water heater*
Total working capital allowance		$ (162,344)	J	
Fixed Assets				
Opening balance - regulated fixed assets (NBV)	$ 12,050,982			
Closing balance - regulated fixed assets (NBV)	$ 11,885,162			*NBV = Net Book Value*
Average regulated fixed assets	$ 11,968,072	$ 11,968,072	K	
Total rate base		**$ 11,805,728**	L = J + K	
Regulated deemed short-term debt	4%	$ 472,229	M	
Regulated deemed long-term debt	56%	$ 6,611,208	N	
Regulated deemed equity	40%	$ 4,722,291	P	
		$ 11,805,728		
Regulated Rate of Return on Deemed Equity				*Comments*
		9.98%	Q = E / P	
ROE% from most recent cost of service application	**last approved EDR**	**9.85%**	R	*Approved ROE from last CoS rate proceeding*
	Allowed	**$465,146**		
Difference - maximum deadband 3%		**0.13%**	S = Q - R	
	Over/(Under)	**$6,110**		
Interest adjustment on deemed debt:				*Comments*
Regulated deemed short-term debt - as above	$ 472,229	6.67%		
Regulated deemed long-term debt - as above	$ 6,611,208	93.33%		
	$ 7,083,437	100.00%		
Short-term debt rate	2.07%	0.14%		*Interest rate on short-term debt from last approved CoS rate proceeding*
Long-term debt rate	7.67%	7.16%		*Interest rate on long-term debt from last approved CoS rate proceeding*
Average debt rate		7.30%		
Regulated deemed debt - as above	$ 7,083,437			
Weighted average interest rate	7.30%			
Deemed interest	$ 516,855 T			
Interest expense as per the OEB trial balance	$ 470,099 U			*As per financial statements*
Difference	$ 46,756 V = T - U			
Utility tax rate	25.12%			*Distributor's Board-approved tax rate from the distributor's last rate application(IRM or CoS).*
Tax effect on interest expense	$ (11,745)			
Interest adjustment on deemed debt:	$ 35,011 W			

REGULATORY EFFICIENCIES

In the absence of a compelling need to re-base, the Board's preference should be to have utilities remain under a PBR regime, such as NRG's IR Plan.

The Board expressed its preference for the move to PBR rate-setting in its January 18, 2000 Decision (RP-1999-0034), wherein it established PBR for electricity distributors:

> ... PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentive for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality.

The current IR Plan is NRG's first experiment with rate-setting under a PBR scheme, and (notwithstanding the built-in Z-factor and off-ramp safeguards) there may have been some reticence about establishing a lengthy term for NRG's initial IR Plan. However, as noted in Exhibit C, Tab 1, Schedules 1 and 2, NRG's earnings have remained within the ROE deadband in Fiscal 2011 and Fiscal 2012, and was only slightly below the ROE deadband in Fiscal 2013.

The efficiency benefits of NRG remaining under the existing IR Plan (as opposed to filing a new cost-of-service application) are as follows:

- Standard PBR Efficiencies: NRG will be incented to continue to find cost savings and efficiencies in order to improve its earnings. Ultimately, these savings will yield lower distribution rates for its customers. This is the basic intent of PBR schemes.
- Board/Intervenor Efficiencies: A re-basing application is not only a burden on NRG, but also on the Board. This two-year extension Application will require far fewer Board

resources. It will also save intervenors the time and money associated with a re-basing application.

- Better Use of NRG's Time: A re-basing application is a major burden on the personnel of any utility, but particularly so for smaller utilities. NRG is a relatively small utility (approximately 8,000 customers). NRG's last cost-of-service filing (EB-2010-0018) consumed months of personnel time (and continues to occupy personnel time on the outstanding system integrity gas issue). NRG's personnel time could be better spent on customer-focused initiatives – for example, the new DSM regime that NRG will have to put in place for January 1, 2015.
- Rate Predictability: A continuation of the existing IR Plan will provide relative rate stability and predictability for NRG's customers.

The Board has continued to take steps to encourage more efficient utility operation through the rate-setting process. In its recent *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 18, 2012), the Board stated:

> The Board's approach to rate-setting must continue to support a sustainable, financially viable and reliable electricity system. It must do so in a manner that is responsive to customer's concerns about affordability, by promoting increased efficiency which in turn can lower costs and provide for more predictable rates. It must also do so in a manner that better accommodates differing circumstances of distributors (for example, with respect to customer expectations, asset profile and investment needs) and facilitates the cost-effective and efficient achievement of expected performance outcomes. Finally, the rate regime must also recognize the inter-connected nature of the electricity system in Ontario, promote ongoing productivity improvements, encourage innovation, and support efficient regulation.

In pursuit of these objectives, the Board established three methods for distributor rate-setting, the shortest of which has a five-year rate period:

- 4th Generation IR (rebasing plus four years)
- Custom IR (minimum term of five years)
- Annual IR Index (no fixed term; annual adjustment mechanism)

The approach is clearly to move electricity distributors to long-term PBR where possible (i.e., five years or more). Although applicable to electricity distributors, NRG is in many ways more similar to an Ontario electricity distributor. NRG is a small utility, and very small in comparison to the province's other two rate-regulated natural gas utilities (Enbridge and Union Gas). For that reason, NRG's current IR Plan was based on the model used for electricity distributors in the province.

NRG's approach in this application is consistent with the Board's policy pronouncements regarding improving regulatory efficiencies via the rate-setting process, and moving to an IR Plan of five years or more.

OUTSTANDING ITEM FROM PREVIOUS RATE CASE

NRG is currently working with a steering committee and two consultants selected via a competitive RFP process, to complete two studies that the Board ordered in Phase 2 of its EB-2010-0018 decision. The studies are underway but not yet complete. They will be completed during the proposed two-year IR Plan extension period.

It is NRG's preference to close out this last remaining issue in EB-2010-0018 before embarking on a full cost-of-service rate proceeding. During the proposed two-year IR Plan extension period, the two studies can be completed and any resultant capital expenditure proposals (e.g., to resolve the system integrity issue) can be properly planned and captured in NRG's next cost-of-service filing.

History of the System Integrity Issue

In NRG's last rate proceeding, the issue of system integrity gas injected into NRG's system by a non-arm's length company (NRG Corp.) was the subject of lengthy discussion and evaluation by the Board and Parties to the proceeding. The issue arose in Phase 1 of the EB-2010-0018 proceeding and continued in Phase 2 of that proceeding.

Following Phase 1 of the Board's Decision in EB-2010-0018, NRG filed a System Integrity Study completed by AUE Utility Engineering ("Original SIS"). That Original SIS ran a simulation model for a cold (-28 deg. C) day with all of NRG Corp.'s producing wells (there are approximately 40 of them) shut in (i.e., producing zero). The simulation results indicated that under that scenario, system pressure would drop, the Aylmer regulator stations would cease to operate and "wide-spread outage will occur". The Original SIS indicated that: "To maintain adequate system pressures without the benefits of well supplies, alternatives must be looked into in bringing fresh gas supply to affected areas, i.e.: the Town of Aylmer and the area just south of Aylmer" (Original SIS, p.9). The Original SIS then went on to look at three alternative approaches to resolving the system integrity issue.

This Original SIS was the subject of consideration and evaluation during Phase 2 of the EB-2010-0018 proceeding. In its Phase 2 Decision, the Board acknowledged the conclusion of the Original SIS, and noted that the system integrity issue was a complex one. As a result, the Board determined that a more detailed independent study was warranted to look at all relevant alternatives to address the system integrity study, and a more robust sensitivity analysis. The Board therefore ordered the formation of a steering committee comprised of Board staff, intervenors and NRG to draft an RFP and terms of reference for an independent study that would: (a) evaluate NRG's ability to source local supply from third-party suppliers in NRG's franchise areas (the "Competitive Market Study"); and (b) conduct a robust sensitivity analysis in order to determine more precisely the quantum of locally-supplied natural gas required to maintain the integrity of NRG's distribution system (the "System Integrity Study").

This steering committee consisted of representatives from NRG (Tony Graat and Bob Cowan), Board Staff (Khalil Viraney) and the Vulnerable Energy Consumers Coalition ("VECC") (James Wightman). It has taken longer than anticipated to conclude this work. Ultimately, it was decided by the steering committee to prepare two separate RFPs (one for the Competitive Market

Study and one for the System Integrity Study). As the steering committee discovered, there were not a great deal of potential entities capable of or interested in replying to the RFPs. That having been said, ultimately RFPs were received, and both the Competitive Market Study and System Integrity Study are now underway.

Link to Two-Year Extension Application

A two-year extension application will enable these studies to be completed and considered by the steering committee, and the record in EB-2010-0018 formally closed prior to NRG filing a new cost-of-service application. It is unknown whether the System Integrity Study will recommend any material capital projects to resolve the system integrity issue, but to the extent that it does, the two-year extension period would potentially allow any material capital projects to be built into NRG's next cost-of-service application.

FINANCIAL FUTURE OF IGPC

IGPC operates an ethanol plant in Aylmer, and is by far NRG's largest distribution customer (accounting for approximately 25% of NRG's distribution revenue). As set out below, a lack of information about IGPC's ability to operate profitably and continue to take natural gas from NRG beyond 2016 means that NRG could not bring forward a new cost-of-service application with a multi-year IR Plan. To do so, NRG would need better information about IGPC's operating grants, and IGPC's plans to operate in the absence of such grants. Consequently, NRG has brought a two-year extension application based on NRG's continued IR Plan.

IGPC's Reliance on Operating Grants

Based on IGPC's financial statements, IGPC appears to be heavily reliant on two operating grants in order to operate profitably: (a) an "ecoEnergy for Biofuels" operating grant, managed by Natural Resources Canada ("NRCan"); and (b) an operating grant from the Ontario Ministry of Agriculture, Food and Rural Affairs ("OMAFRA"). The operating grant amounts vary modestly from year-to-year (being dependent on production volumes), but both are material to IGPC's revenues. The provincial operating grant from OMAFRA appears to be slightly greater than the NRCan grant. For example, in fiscal 2012, the provincial OMAFRA operating grant was $14.9 million and the federal NRCan grant was $12.4 million.

IGPC's financial statements indicate that these grants are set to expire in 2016 (see Exhibit C, Tab 4, Schedules 2 through 5). Moreover, as of February 2013, the federal government appears to have cancelled the NRCan "ecoEnergy for Biofuels" program, with no further applications being received after 2010 and no committed grant money paid out beyond 2017 (see Exhibit C, Tab 4, Schedule 6).

The loss of IGPC's operating grants is of significant concern to NRG because IGPC's annual net income has consistently been far less than the sum of its two annual operating grants (see the Consolidated Statement of Operations and Retained Earnings/Deficit at Exhibit C, Tab 4, Schedules 2 through 5 inclusive):

IGPC's Fiscal Year Ending September 30	IGPC's Net Income	IGPC's Operating Grants	Loss Without Grants
2009	$4.7 million	$26.8 million	**$22.1 million**
2010	$12.4 million	$27.1 million	**$14.7 million**
2011	$11.7 million	$28.7 million	**$17.0 million**
2012	$11.9 million	$27.5 million	**$15.6 million**

In the absence of the operating grants, IGPC would have operated at a loss in every year from 2009 to 2012. Consequently, NRG is concerned about IGPC's post-2016 profitability and its ability to take gas from NRG beyond 2016.

Lack of Financial Information Provided by IGPC

NRG has tried unsuccessfully to obtain more recent financial information for IGPC, as well as information about IGPC's plans in the event that the operating grants are not renewed (see correspondence at Exhibit C, Tab 4, Schedule 7). IGPC has refused to provide such information to NRG. The information in the table above was obtained without IGPC's assistance, and IGPC has now prevented access to its financial statements by requiring a member password to access them on the IGPC website.

In short, NRG has a number of information gaps about IGPC and its future operations, including the following fundamental pieces of information:

- whether IGPC will renew its GDC with NRG and continue to receive gas beyond this coming April, and if it does, whether it will renew at its current minimum annual volume (33,416,618 m^3) and whether IGPC will commit to a new GDC term beyond 2016;
- whether IGPC's operating grants have been renewed, and if not when IGPC expects to find out whether they will be renewed; and,
- if the operating grants are not renewed, or only one is renewed, how IGPC proposes to operate profitably or at the same gas consumption levels.

This information gap forms the basis for NRG's request to have certain financial and business information produced by IGPC in this proceeding. The information, of course, can be provided confidentially if necessary. With respect to any future (post-2016) plans, NRG believes that they must be more than merely a hopeful business plan. NRG believes this is warranted given the size of IGPC's distribution revenue in relation to NRG's overall revenues – even a material decrease in IGPC's consumption would have a material impact on NRG's business that would have to be accounted for in NRG's next cost-of-service application or (in the absence of any timely information from IGPC) potentially a Z-factor application.

This lack of information makes bringing forward any new IR Plan beyond 2016 virtually impossible. A two-year extension to NRG's current IR Plan would provide additional time to resolve the problem caused by IGPC's refusal to provide relevant financial information to NRG.

This information is needed very soon because in order to file a full cost-of-service application in time for the Board to process and ultimately render a decision in time for October 1, 2016, the preparation of that application and evidence will need to begin in 2015.

By the time that NRG needs to file its next cost-of-service application (early 2016), IGPC will have had to renew its Gas Delivery Contract with NRG (set to expire in April 2015). Of importance to NRG will be whether IGPC requests to renew at the same volume levels, and whether IGPC renews for a term beyond 2016.

Integrated Grain Processors Co-operative Inc.

Consolidated Financial Statements
September 30, 2009

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
Chartered Accountants
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London, Ontario
Canada N6A 5P4
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January 13, 2010

Auditors' Report

To the Shareholders of
Integrated Grain Processors Co-operative Inc.

We have audited the consolidated balance sheet of **Integrated Grain Processors Co-operative Inc.** (the "Co-operative") as at September 30, 2009 and the consolidated statements of operations and deficit, and cash flows for the year then ended. These financial statements are the responsibility of the Co-operative's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Co-operative as at September 30, 2009 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Licensed Public Accountants

Integrated Grain Processors Co-operative Inc.

Consolidated Balance Sheet

As at September 30, 2009

	2009 $	2008 $
Assets		
Current assets		
Cash	7,540,769	3,273,263
Restricted cash (note 3)	4,699,344	6,918,823
Accounts receivable (note 4)	15,183,769	754,782
Inventory (note 5)	3,907,394	3,747,594
Prepaid expenses	603,244	559,574
Fair value of commodity derivative contracts (note 15)	226,501	-
Future income taxes	549,000	1,782,000
	32,710,021	17,036,036
Property, plant and equipment (note 6)	85,947,990	11,945,393
Construction in progress (note 7)	-	98,097,527
Intangible assets	3,227,324	3,227,324
Future income taxes	336,000	315,000
	122,221,335	130,621,280
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities (note 8)	6,992,236	20,749,682
Current portion of term debt (note 9)	7,337,688	-
Bank debt due within one year (note 9)	-	53,141,426
Current portion of capital lease obligation (note 10)	464,433	400,658
Fair value of interest rate swap contracts (note 20)	2,042,963	1,284,867
	16,837,320	75,576,633
Capital lease obligation (note 10)	3,726,053	4,194,536
Subordinated debentures and notes (note 11)	2,384,500	2,447,000
Term debt (note 9)	42,625,314	-
Research and development fund liability (note 17)	1,708,500	-
Future income taxes	1,160,000	182,000
	68,441,687	82,400,169
Shareholders' equity		
Common shares (notes 8 and 12)	53,036,960	52,209,960
Contributed surplus (note 22)	906,150	906,150
Deficit	(163,462)	(4,894,999)
	53,779,648	48,221,111
	122,221,335	130,621,280

Approved by the Board of Directors

_________________ Director _________________ Director

Integrated Grain Processors Co-operative Inc.

Consolidated Statement of Operations and Deficit

For the year ended September 30, 2009

	2009 $	2008 $
Net sales	89,382,111	-
Cost of goods sold	91,209,893	-
Depreciation and amortization	6,309,950	
Net gain on commodity derivative contracts	(36,746)	-
Operating grants (note 17)	(26,835,865)	-
	70,647,232	-
Gross profit	18,734,879	-
Selling, general and administrative expenses	3,396,720	2,433,444
Depreciation and amortization	1,948,324	45,902
	5,345,044	2,479,346
Operating income (loss)	13,389,835	(2,479,346)
Other income (expenses)		
Government grants	-	50,000
Interest expense (note 18)	(5,622,995)	-
Interest income	48,640	15,340
Loss on interest rate swap (note 20)	(758,096)	(1,284,867)
Loss on foreign exchange	(48,847)	(16,315)
	(6,381,298)	(1,235,842)
Income (loss) before provision for (recovery of) taxes	7,008,537	(3,715,188)
Provision for current income taxes	87,000	-
Provision for (recovery of) future income taxes	2,190,000	(1,104,074)
	2,277,000	(1,104,074)
Net income (loss) for the year	4,731,537	(2,611,114)
Deficit – Beginning of year	(4,894,999)	(2,283,885)
Deficit – End of year	(163,462)	(4,894,999)

Integrated Grain Processors Co-operative Inc.

Consolidated Statement of Cash Flows

For the year ended September 30, 2009

	2009 $	2008 $
Cash flows from operating activities		
Net income (loss) for the year	4,731,537	(2,611,114)
Changes (credits) to income not involving cash:		
Depreciation and amortization	8,258,274	45,902
Unrealized gain on commodity derivative contracts	(226,501)	-
Loss on interest rate swap contracts	758,096	1,284,867
Interest on research and development fund liability	54,579	-
Future income taxes	2,190,000	(1,104,074)
	15,765,985	(2,384,419)
Net change in non-cash working capital balances (note 21)	(3,748,711)	(2,679,914)
	12,017,274	(5,064,333)
Cash flows from financing activities		
Net proceeds and repayments from subordinated debentures and notes (note 9)	(62,500)	2,447,000
Net proceeds and redemptions of share subscriptions (note 12)	827,000	5,057,300
Proceeds from credit facility (note 9)	18,711,156	58,988,844
Payment of bridge facility (note 9)	(14,000,000)	-
Payment of term debt (note 9)	(9,728,812)	-
Payment of capital lease obligation	(404,708)	-
Deferred financing costs (note 9)	(36,368)	(917,544)
Decrease (increase) in restricted cash (note 3)	2,219,479	(4,261,141)
	(2,474,753)	61,314,459
Cash flows from investing activities		
Purchase of property and equipment	(959,121)	(789,964)
Construction in progress	(18,315,894)	(59,828,979)
Proceeds from OMAFRA capital grant (note 17)	14,000,000	-
	(5,275,015)	(60,618,943)
Net increase (decrease) in cash	4,267,506	(4,368,817)
Cash – Beginning of year	3,273,263	7,642,080
Cash – End of year	7,540,769	3,273,263

1 Nature of operations

Integrated Grain Processors Co-operative Inc. (the "Co-operative") was incorporated on April 4, 2002 under the Ontario Co-operative Corporations Act.

The Co-operative produces and sells ethanol and distillers grain through its 150 million litre fuel ethanol production facility in south western Ontario, which was completed on October 15, 2008. In the prior year, the Co-operative had not commenced operations and was considered to be in the construction phase.

2 Summary of significant accounting policies

Principles of consolidation

The consolidated financial statements include the financial statements of the Co-operative and its wholly-owned subsidiary, IGPC Ethanol Inc. (the "Subsidiary"). Intercompany balances and transactions have been eliminated on consolidation.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the year reported. Actual results could differ from those estimates.

Revenue recognition

The Co-operative recognizes revenue on the sale of ethanol and distillers grains at the time of shipment.

Government assistance

Government grants are recognized when there is reasonable assurance that the Co-operative has complied with the conditions of the grant. Such grants are accounted for as reduction of the related expense or asset, or as income, as appropriate.

Inventories

Inventories of finished products, feedstock, process chemicals and supplies are valued at the lower of net realizable value and average cost. Work in process consists of cost of material and direct labour and is valued at the lower of net realizable value and average cost.

Property, plant and equipment

Property, plant and equipment are stated at cost. Amortization is provided for in the accounts as follows:

Buildings and site pipelines	5% declining balance
Furniture and fixtures	20% declining balance
Equipment	30% declining balance
Process equipment	10 to 15 years substantially by straight line
Gas pipeline under capital lease	7 years straight line

In the year of acquisition, amortization is provided for at one-half of the above rates, except in 2009 when the cost of the process plant was transferred from construction in progress to the appropriate asset categories and amortization was provided for from the date of production. No amortization is provided for in the year of disposal or until assets are put into service.

The total cost of major capital projects includes related interest incurred during the period of construction. Capitalization of interest ceased on October 15, 2008 when the capital asset was substantially complete and ready for its intended productive use.

Grants under government capital assistance programs are deducted from the cost of the assets to which the grant relates.

Intangible asset

The intangible asset recorded on the balance sheet, relates to the right to use the proprietary design and processes to produce ethanol.

Intangible property is tested for impairment annually, or more frequently, if events or changes in circumstances indicate that it might be impaired. The impairment test consists of a comparison of the expected future operating cash flows (on an undiscounted basis) with its carrying amount. When the carrying amount exceeds the expected future cash flows, an impairment loss is recognized in an amount equal to the excess.

Financial instruments

Under CICA Handbook Section 3855, financial assets and liabilities, including derivative instruments, are initially recognized and subsequently measured based on their classification as held-for-trading, available-for-sale financial assets, held-to-maturity, loans and receivables, or other financial liabilities as follows:

- Held-for-trading financial instruments are measured at their fair value with changes in fair value recognized in net income for the year.
- Available-for-sale financial assets are measured at their fair value and changes in fair value are included in other comprehensive income until the asset is removed from the balance sheet.
- Loans and receivables are measured at cost or amortized cost using the effective interest rate method.

- Other financial liabilities are measured at cost or amortized cost using the effective interest rate method

- Derivative instruments, including embedded derivatives, are measured at their fair value with changes in fair value recognized in net income for the year unless the instrument is a cash flow hedge and hedge accounting applies in which case changes in fair value are recognized in other comprehensive income.

The following is a summary of the classification of assets and liabilities of the Co-operative:

Financial Instrument	**Classification**
Cash	Held-for-trading
Restricted cash	Held-for-trading
Accounts receivable	Loans and receivables
Fair value of commodity derivative contracts	Derivative instrument (non-hedge)
Accounts payable and accrued liabilities	Other financial liabilities
Fair value of interest rate swap contracts	Derivative instrument (non-hedge)
Capital lease obligation	Other financial liabilities
Subordinated debentures and notes	Other financial liabilities
Term and bank debt	Other financial liabilities
Research and development fund liability	Other financial liabilities

CICA Handbook Sections 3862 and 3863 place an increased emphasis on disclosure about the nature and extent of risks arising from financial instruments and how the entity manages those risks. The Co-operative has elected not to adopt these accounting standards as a non-public enterprise.

Deferred financing costs

Transaction costs related to the credit agreement are netted against the carrying value of the term loan and are amortized over the duration of the credit agreement using the effective interest rate method, based on target debt levels of the term loan and expect levels of available credit under the revolving term facility.

Interest rate swap contracts

Exposure to interest rates on debt is managed through the use of interest rate swap contracts. These swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Settlement amounts under interest rate swap contracts have been included in capitalized interest during the pre-operating period prior to October 15, 2008. Changes in the fair value of the interest rate swap contracts have been recorded in the statement of operations.

Stock options

Options are accounted for under the fair market method. Stock-based compensation costs, measured at the grant date based on the fair value of the options granted and recognized over the service period involved, are recorded as expenses on the income statement. The amounts are credited to contributed surplus. The consideration paid upon exercise of the options and the originally recorded fair value of the options are added to share capital.

Income taxes

The liability method of accounting for income taxes is used. Under this method, future income tax assets and liabilities are determined based on the differences between the carrying amount of assets and liabilities and the tax cost bases of these assets and liabilities measured using substantially enacted income tax laws and rates.

New accounting recommendations

a) Goodwill and intangible assets

Section 3064, issued in February 2008, provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets, other than initial recognition of goodwill and intangible assets acquired in a business combination. The standard is effective for fiscal periods beginning on or after October 1, 2008, and requires retroactive application to prior period financial statements.
The Co-operative adopted this standard regarding asset recognition in the financial statements with no changes required.

b) Inventories

CICA Handbook Section 3031, issued in June 2007, establishes new standards on the determination of cost and requires inventories to be measured at the lower of cost and net realizable value. The cost of inventories includes the cost to purchase and other costs incurred in bringing the inventories to their present location. The new standard also requires additional disclosures regarding the accounting policies used in measuring the inventories, the carrying value of the inventories, amounts recognized as an expense during the period, write-downs and the amount of any reversal of write-downs recognized in the period. The standard is effective for fiscal periods beginning on or after January 1, 2008. Adoption of the standard did not have any impact on the financial statements.

c) Intangible assets

CICA Handbook Section 3064, issued in February 2008, provides guidance on the recognition, measurement, presentation and disclosure for goodwill and intangible assets, other than initial recognition of goodwill and intangible assets acquired in a business combination. The standard is effective for fiscal periods beginning on or after October 1, 2008, and requires retroactive application to prior period financial statements. Adoption of the standard did not have any impact on the financial statements.

d) Capital disclosures

CICA Handbook Section 1535, issued in December 2006, specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements and (iv) if it has not complied, the consequences of such non-compliance. Recommended disclosures from this section have been included in note 13 of these financial statements.

e) Going concern

In April 2007, the CICA approved amendments to CICA Handbook Section 1400, General Standards of Financial Statement Presentation. These amendments require management to assess an entity's ability to continue as a going concern. When management is aware of material uncertainties related to events or conditions that may cast doubt on an entity's ability to continue as a going concern, those uncertainties must be disclosed. In assessing the appropriateness of the going concern assumption, the standard requires management to consider all available information about the future, which is at least, but not limited to, twelve months from the balance sheet date. The new requirements of the standard are applicable for interim and annual financial statements relating to fiscal years beginning on or after January 1, 2008. Adoption of the standard did not have any impact on the financial statements.

f) Credit risk and the fair value of financial assets and financial liabilities

On January 20, 2009, the Emerging Issues Committee ("EIC") of the Accounting Standards Board issued EIC Abstract 173, *"Credit Risk and the Fair Value of Financial Assets and Financial Liabilities"*, which establishes guidance requiring an entity to consider its own credit and the credit risk of the counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. EIC 173 should be applied retroactively, without restatement of prior periods. The adoption of this interpretation did not have a significant impact on the Co-operative's financial statements.

Future accounting recommendations

a) Business combinations

CICA Handbook Section 1582 will improve the relevance, reliability and comparability of the information that a reporting entity provides in its financial statements about a business combination and its effects. This section outlines a variety of changes, including but not limited to the following: an expanded definition of a business, a requirement to measure all business combinations and non-controlling interest at fair value and a requirement to recognize future income tax assets and liabilities and acquisition and related costs as expenses of the period. The standard is effective for fiscal periods beginning on or after January 1, 2011. The Co-operative is currently reviewing the impact of this standard and will adopt the standard commencing in fiscal 2012.

b) Consolidated financial statements and non-controlling interests

CICA Handbook Sections 1601 and 1602 will replace CICA Handbook - Section 1600, *"Consolidated Financial Statements"*. Section 1601 establishes standards for the preparation of consolidated financial statements and specifically addresses consolidation accounting following a business combination that involves the purchase of an equity interest in one company by another. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard is effective for fiscal periods beginning on or after

January 1, 2011. The Co-operative is currently reviewing the impact of this standard and will adopt the standard commencing in fiscal 2012

c) International Financial Reporting Standards

The Canadian Accounting Standards Board requires all publicly accountable enterprises to adopt International Financial Reporting Standards (IFRS) for interim and annual financial statements for fiscal years beginning on or after January 1, 2011. Companies will be required to provide IFRS comparative information for the previous fiscal period. The transition from Canadian generally accepted accounting principles to IFRS will be applicable for the Co-operative's fiscal 2012. While the adoption of IFRS would impact the financial statements of the Co-operative, the Co-operative is assessing whether it will adopt IFRS.

3 Restricted cash

	2009 $	2008 $
Debt service reserve account	4,484,689	4,168,720
Cash on account - letters of credit	-	2,750,103
Post completion account	214,655	-
	4,699,344	6,918,823

Under the terms of the credit agreement, as construction funds were obtained, a portion was added to the debt service reserve account such that at substantial completion the sum of two principal instalments plus six months of interest is available in a separate account to service bank debt. In the event cash flow is insufficient to meet the quarterly requirement, these funds may be used but must be replenished.

Prior to substantial completion and access to the operating line of credit, the Co-operative was required to maintain cash in a separate account for certain letters of credit. The primary letters of credit were for security for corn procurement ($2,500,000) and gas delivery ($232,667). During the year, these funds were released and the collateral was replaced with the revolving term facility (note 9).

4 Accounts receivable

	2009 $	2008 $
Trade accounts receivable	1,129,194	-
Operating grant receivable (note 17)	5,891,353	-
Capital grant receivable (note 17)	7,277,514	-
Deposit on account with derivative contract supplier	647,424	-
Other receivables	238,284	754,782
	15,183,769	754,782

5 Inventory

	2009 $	2008 $
Fuel grade ethanol	1,767,813	-
Work in process	533,402	251,464
Feedstock, process chemicals and supplies	1,606,179	3,496,130
	3,907,394	3,747,594

6 Property, plant and equipment

			2009
	Cost $	Accumulated Amortization $	Net $
Land	2,923,721	-	2,923,721
Building	13,615,335	647,412	12,967,923
Site pipelines	2,287,513	129,541	2,157,972
Furniture and fixtures	70,228	17,337	52,891
Equipment	621,364	159,211	462,153
Process equipment	64,395,889	4,274,748	60,121,141
Gas pipeline under capital lease (note 10)	8,472,554	1,210,365	7,262,189
	92,386,604	6,438,614	85,947,990

			2008
	Cost $	Accumulated Amortization $	Net $
Land	2,828,881	-	2,828,881
Building	400,000	8,000	392,000
Furniture and fixtures	45,559	7,197	38,362
Equipment	363,437	40,741	322,696
Gas pipe line under capital lease (note 10)	8,363,454	-	8,363,454
	12,001,331	55,938	11,945,393

In the current year, the Co-operative has received or recognised capital grants from the Government for plant construction costs in the amount of $19,623,593 (2008 - $10,710,000), which are netted against the total cost of the ethanol plant.

7 Construction in progress

	2009 $	2008 $
Plant equipment and buildings	-	95,409,588
Capitalized interest (note 18)	-	2,687,939
	-	98,097,527

8 Accounts payable and accrued liabilities

The engineering procurement and construction (EPC) company agreed to defer $3,904,712 of the amounts owing under the Design/Build Agreement pending Co-operative's receipt of payment under the ecoAgriculture Biofuels Capital Initiative agreement (note 17). In return, the payable is interest bearing ($1,701,602 at 8.5% as of August 31, 2008 and $2,203,100 at 8.0% as of November 30, 2008). In the event that full repayment of amounts owing are not repaid by October 15, 2009, EPC has the option to convert $4.00 of debt and accrued interest into one Class A Preference Shares of the Co-operative with a par value $5.00. This payable amount has been included in accounts payable and accrued liabilities. Subsequent to year end, the amount owing was repaid and the option is no longer effective.

9 Bank debt

	2009 $	2008 $
Term debt	53,971,188	-
Construction facility	-	48,360,222
Bridge facility	-	10,628,622
	53,971,188	58,988,844
Less: Current portion	(7,337,688)	(53,141,426)
Less: Deferred financing costs	(4,008,186)	(5,847,418)
	42,625,314	-

The Co-operative entered into a credit agreement on June 15, 2007 with a lead bank as Agent for certain lenders to initially make the following credit facilities available:

a) A seven year non-revolving term loan facility for $63,700,000 to be used for construction of the plant with principal payments of $3,822,000 commencing in 2009, due June 27, 2014.

b) Certain non-revolving bridge facilities for construction costs prior to receipt of government funding in the amount of $14,000,000.

c) A seven year revolving term facility for working capital purposes not to exceed lesser of $7,000,000 or the borrowing base. Borrowing base uses as collateral 85% of eligible receivables and inventory.

During the year, the Co-operative had drawn the full amount allowed against the seven year non-revolving term loan facility. The revolving facility became available after substantial completion of the ethanol plant as defined under the credit agreement.

The credit agreement also provided a short-term bridge facility for $14,000,000 which was repaid in March 2009 when the Co-operative received the $14,000,000 capital grant from OMAFRA (note 17).

Deferred financing costs have been allocated to the term loan, revolving term facility and bridge facility. At year-end the unamortized balances allocated to these elements of the credit agreement are $3,233,786, $744,400 and Nil respectively.

As at September 30, 2009, the Co-operative had $2,754,481 of letters of credit drawn against the seven year revolving term facility.

During construction, interest is based on the variable banker's acceptance rate and a stamping fee of 3.75%. After substantial completion, the debt becomes a term debt with interest at the variable banker's acceptance rate and a stamping fee of 3.25% which was increased to 4.00% after negotiating the amendment to the credit agreement. The aggregate amount of principal payments required in each of the next five years under debt facilities are:

	$
2010	7,337,688
2011	3,822,000
2012	3,822,000
2013	3,822,000
2014	35,167,500
	53,971,188

Debt repayments made on each repayment date will be the greater: of 70% of excess cash flows; and the difference between the outstanding amount and the target outstanding debt to a maximum of 100% of the excess cash flows. The target outstanding debt is reduced by $3,033,333 per quarter. If there are no excess cash flows, the Company is required to pay 1.5% of the initial debt outstanding for a total of $955,500 per quarter, which has been disclosed in the principal payments required and adjusted for the December 2009 payment totalling $4,471,188. As at September 30, 2009, the target debt outstanding was $57,633,333. A voluntary prepayment feature allows the Company to prepay a minimum of $500,000 with adequate notice to the Agent.

Under the credit agreement, the Co-operative has provided security to the lenders, the key elements of which are as follows:

a) a fixed and floating charge debenture in the amount of $150 million;
b) a general security agreement covering all assets of the Co-operative;
c) an assignment of insurance; and
d) a limited recourse guarantee and a securities pledge agreement.

10 Capital lease obligation

As part of the construction of the ethanol plant, it was necessary for the local natural gas distributor to construct a 29 km pipeline from a Union Gas trunk pipeline to the town of Aylmer. The costs of the pipeline are fully borne by the Co-operative, through 'aid-to-construct' payments, plus certain fixed gas delivery charges over a 7 year contract period. While the Co-operative has no ownership interest in the pipeline, accounting guidelines require that in such instances where the value of the asset is fully recovered by the supplier and the customer has exclusive, or virtually exclusive, use of the asset, the arrangement is accounted for as a lease.

Accordingly, the Co-operative has recorded the capital cost of the pipeline as a capital lease, and the discounted value of certain fixed gas delivery charges over the next 7 years as a capital lease obligation, with notional interest of 15%. The details of the capital lease obligation are as follows:

	$
Future minimum lease payments:	
2010	1,066,252
2011	1,066,252
2012	1,066,252
2013	1,066,252
2014	1,066,252
2015	1,066,252
	6,397,512
Amounts representing interest	2,207,026
	4,190,486
Less: Current portion	464,433
Long-term portion	3,726,053

In addition to the foregoing, the Co-operative is obligated to provide a letter of credit to the natural gas distributor to ensure performance under the agreement. At year end, a letter of credit in the amount of $5,214,173 (2008 - $5,214,173) was issued in their favour.

11 Subordinated debentures and notes

	2009 $	2008 $
Class A debentures maturing on December 31, 2013 and bearing interest at 8.5% per annum	1,070,000	895,000
Class B debentures maturing on December 31, 2013 and bearing interest at 7.5% per annum	37,000	27,000
Promissory notes maturing on December 31, 2010 and bearing interest at 8% per annum	1,277,500	1,525,000
	2,384,500	2,447,000

The redemption of these subordinate debentures at maturity and the payment of interest thereon are subject to the prior consent of the lenders to the Co-operative. Subsequent to year end, with the consent of the lenders, $545,530 was repaid with respect to the promissory notes.

12 Capital stock

Authorized

100,000 Membership Shares, voting, with a par value of $100 each.

11,000,000 Class A Preference Shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class B Preference Shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class C Preference Shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class D Preference Shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class A and Class B preference shares are redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately proceeding fiscal year subject to certain conditions. The Class C and D preference shares are redeemable at their par value. The preference shares do not carry a retraction right.

Each of the Class A, B, C, and D preference shares are entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

During the year, 30 Membership Shares (2008 - 95), 168,000 Class A Preference Shares (2008 - 1,004,160) and 1,000 Class B Preference Shares (2008 - 5,400) were issued for cash consideration of $3,000 (2008 - $9,500), $840,000 (2008 - $5,020,800) and $5,000 (2008 - $27,000) respectively.

Issued and fully paid	Membership		Class A		Class B		Class C		Class D		Total
	#	$	#	$	#	$	#	$	#	$	$
Issued at October 1, 2007	4,140	414,000	9,266,199	45,745,995	189,313	946,565	800	4,000	8,420	42,100	47,152,660
New subscriptions	95	9,500	1,004,160	5,020,800	5,400	27,000	-	-	-	-	5,057,300
Redemptions	-	-	-	-	-	-	-	-	-	-	-
Balance, September 30, 2008	4,235	423,500	10,270,359	50,766,795	194,713	973,565	800	4,000	8,420	42,100	52,209,960
New subscriptions	30	3,000	168,000	840,000	1,000	5,000	-	-	-	-	848,000
Redemptions	(10)	(1,000)	-	-	(4,000)	(20,000)	-	-	-	-	(21,000)
Balance, September 30, 2009	4,255	425,500	10,438,359	51,606,795	191,713	958,565	800	4,000	8,420	42,100	53,036,960

13 Capital disclosures

The Co-operative has two primary capital management objectives. The first of which is to raise and maintain a capital base to finance the construction and operation of an ethanol manufacturing facility. In compliance with the credit agreement, membership and preference shares and subordinate debentures ("securities") have been issued. These securities are governed by the Co-operative Corporations Act. Annually, an Offering Statement is filed with the Superintendent (Financial Services Corporation of Ontario).

The second primary capital management objective is to safeguard the Co-operative's ability to continue as a going concern so that it can provide returns to its shareholders and benefits for other stakeholders. In this context, management considers capital to be its net worth as defined in the credit agreement as containing shareholders' equity and capital grants. The agent for the syndicate of the term debt has imposed certain covenants in connection with the term debt and credit facilities. As at September 30, 2009, the Co-operative was in compliance with these covenants.

14 Financial instruments

Fair value

The fair value of financial instruments, such as cash, restricted cash, accounts receivable, and accounts payable and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Commodity and currency contracts and the interest rate swap contract are carried at fair value.

The research and development fund liability has been recorded at fair value at the time of recognition and is carried at amortized cost (note 17).

Management has not determined the fair value of its bank debt, capital lease obligations or subordinated debentures and notes.

Credit risk

The Co-operative's exposure to credit risk relates to its accounts receivable. Due to the exclusive marketing arrangements for ethanol and distillers grains, all of the trade accounts receivables are with two customers.

Interest rate risk

The Co-operative is exposed to fluctuations in interest rates on its cash, restricted cash, and term debt. A portion of this risk due to variable interest rates has been addressed by the use of interest rate swap contracts (note 20).

15 Commodity derivative contracts

The Co-operative is exposed to the impact of market fluctuations associated with commodity prices. It anticipates the use of derivative financial instruments as part of an overall strategy to manage market risk, assuming it has sufficient liquidity to manage such a strategy. The Co-operative intends, when able, to use cash, futures, swaps, costless collars and option contracts to mitigate against the risk of changes to the commodity prices of corn, natural gas and ethanol. The Co-operative will not enter into these derivative financial instruments for trading or speculative purposes, nor will it designate these contracts as cash flow or fair value hedges for accounting. These financial instruments are accounted for using the mark-to-market method, with any changes in fair value immediately recognized in operations.

At September 30, 2009, the Co-operative had the following derivative contracts outstanding:

	Average cost/price in USD	Expiry
Corn	$3.34 - $3.36/bushel	Dec 2009 – Mar 2010
Ethanol	$1.61/US gallon	Nov 2009 – Jan 2010
Natural gas	$5.25 - $6.25/MMBtu	Dec 2009 – Mar 2010
RBOB*	$1.665 - $1.945/US gallon	Nov 2009 – Oct 2010

The net market value of these open positions is an unrealized gain of $226,501 (US$ 211,545).

(* RBOB – reformulated gasoline blendstock for oxygenate blending)

16 Commitments

Corn supply agreement

The Co-operative has entered into an exclusive agreement for the supply of corn for production of ethanol for an initial term of five years from October 1, 2008, and it is expected that 350,000 metric tonnes are to be supplied each year. The Co-operative is also required under the agreement to provide adequate assurance for the corn supplier's mark-to-market exposure over a pre-determined threshold.

Risk management agreement

The Co-operative has entered into an agreement with a risk management services provider to implement an integrated price risk management program for an initial term of one year from June 22, 2007 and is automatically renewed each year for an additional one year term.

Ethanol marketing agreement

The Co-operative has entered into an exclusive agreement with an ethanol marketer for the marketing of all of the ethanol production for an initial term of one year from the first day of production, which was October 15, 2008, and the agreement has been renewed for an additional two year term. The ethanol marketing company has agreed to take and pay for 100% of the output.

Distillers grain purchaser agreement

The Co-operative has entered into an exclusive agreement with a marketer to market the following by-products of ethanol production: dry grains with solubles, wet grains with solubles, and wet modified grains with solubles for an initial term of five years from the first day of production, which was October 15, 2008.

17 Government grants

Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA)

The Co-operative has been awarded two grants from OMAFRA.

a) In March 2009, the Company received a capital grant of $14,000,000 after completion of the project and achieving nameplate capacity by establishing the capability of producing 145 million litres of ethanol in a calendar year. As a condition precedent to receiving the grant, the Company is committed to contribute $2,800,000 over ten years to a future industry related Research and Development Fund, as administered by the Agricultural Research Institute of Ontario. The first payment is to be made on April 1, 2012, three years after the full grant was received. An amount of $1,653,921, representing the present value of these payments discounted at 6.6%, was recorded as a research and development fund liability, thus reducing the amount of capital grant recognized for the purpose of recording the net cost of capital assets.

b) An operating grant was activated when the plant began operation in October 2008. Funding is based on the actual volume of denatured ethanol produced in a month times the rate of payment for that month (not to exceed $0.11 per litre) subject to an annual maximum of 145 million litres. During the year, the Co-operative reached this maximum and earned $12,700,695 in operating grants ($0.0876 per litre), of which $1,895,591 has been accrued in accounts receivable. The agreement is set to expire December 31, 2016.

If the profitability of the Co-operative reaches or exceeds the threshold of 17.5% as calculated by the internal rate of return on a cash flow basis, the grant is reduced by 40%. This reduction increases incrementally up to 100% if profitability remains above 17.5%. As at September 30, 2009, the Co-operative's internal rate of return was below the threshold of 17.5%.

Ethanol Expansion Program contribution

This capital grant, managed by NRCan (Natural Resources Canada), will reimburse $11,900,000 of construction costs for the ethanol facility. The Co-operative has received $10,710,000 of contribution which has been netted against construction costs. The balance of $1,190,000 is to be received by the Co-operative after the completion of the government's audit process. The balance has been accrued as an amount receivable.

For each of the calendar years from 2009 to 2016 inclusive or until the grants have been repaid in full, the Co-operative must repay an amount calculated as of December 31 of each year as follows:

(Average Gross Income per Litre minus $0.20 per litre) X the total Fuel Ethanol Produced in the previous twelve (12) months X .20

If the average gross income per litre is $0.20 or less, the repayment will be zero.

ecoEnergy for Biofuels

The Company qualified for an operating grant under the Federal Government's ecoEnergy for Biofuels program, managed by NRCan. The operating grant is payable quarterly, from 2008 to 2016. The maximum incentive rate payable declines from $0.10 per litre of ethanol sold in the first year to $0.04 per litre in the last. The maximum eligible sales volume is 162,000,000 litres per year. During the year, the Company earned $14,135,170 in operating grants ($0.0957 per litre) of which $3,995,762 has been accrued as an amount receivable.

EcoAgriculture Biofuels Capital Program contribution

On March 27, 2009, Agriculture and Agri-Food Canada signed an amendment to the agreement which increase the grant to $6,087,514 (2008 - $3,952,412). The grant is based on eligible project costs and maintaining a minimum level of investment in its parent by agriculture producers. This grant is to be received by the Co-operative after the completion of the government's audit process. The balance has been accrued as an amount receivable.

This is a repayable contribution agreement. To retain the grant, agricultural producer investment must be maintained until at least the second anniversary date of commissioning.

18 Interest

	2009 $	2008 $
Term debt	3,455,030	2,417,197
Settlement interest on swap	1,104,861	255,056
Subordinated debentures and notes	218,996	-
Other	382,052	125,678
Capital lease obligation	666,566	-
	5,827,505	2,797,931
Less: Interest income	-	109,992
Less: Capitalized interest (note 7)	204,510	2,687,939
Net interest expense	5,622,995	-

19 Income taxes

The Co-operative has non-capital losses available of $1,240,845 (2008 – $12,421,888) expiring between 2027 and 2029 that may only be offset against future taxable income. Non-capital losses can be carried forward for 20 years. In addition, the Co-operative has capital losses available for carry-forward of $736,539 (2008 – $736,539) that may be offset against future capital gains. These losses have no expiry date. The Co-operative has recognized the benefit of the non-capital losses as these are expected to be recovered, while the benefit of the capital loss has not been recognized.

20 Interest rate swap contracts

Under the terms of the credit agreement, on August 30, 2007, the Co-operative entered into monthly interest rate swap contracts to match the construction drawdown and term debt repayment schedule. These swap agreements convert a portion of the variable-rate liability into a fixed-rate liability. At September 30, 2009, the unrealized loss on these interest rate swap agreements was $2,042,963 (2008 - $1,284,867).

Terms of the agreement at September 30, 2009 are as follows:

Termination date:	June 1, 2014
Notional amount of principal (maximum):	$27,506,818 (2008 - $31,850,000)
Fixed paying rate:	4.91%

21 Net change in non-cash working capital balances

	2009 $	2008 $
(Increase) decrease in -		
Accounts receivable	(7,151,473)	(61,435)
Inventories	(159,800)	(3,747,594)
Prepaid expenses	(43,670)	(559,203)
Increase (decrease) in -		
Accounts payable and accrued liabilities	3,606,232	1,688,318
	(3,748,711)	(2,679,914)
Cash paid (received) during the year for:		
Interest paid	4,295,943	3,035,667
Interest received	(54,302)	(125,332)
Income taxes	-	-

22 Stock options

Integrated Grain Processors Co-operative Inc. is authorized to grant certain directors options to purchase Class A Preference Shares of the Co-operative.

The Co-operative has also authorized $99,500 worth of Class A Preference Share options to a non-employee for services provided leading up to obtaining financing. When exercised, the fair value of the shares will equal cost of the services provided.

These options vest when exercised and under the Co-operative Corporations Act are exercisable at $5.00 per share until they expire on June 24, 2017. They will be deemed to have been automatically exercised immediately before any change in control of the Co-operative or before the sale of substantially all of its assets.

	2009 **$**	**2008** **$**
Options granted to acquire 139,060 Class A Preference Shares to directors	695,300	695,300
Options granted to acquire 19,900 Class A Preference Shares to a supplier	99,500	99,500
Options granted to acquire 5 Membership shares to a supplier	500	500
Total stock options – end of year	795,300	795,300

23 Contingencies

The Co-operative has been named as a defendant in a lawsuit arising from the construction of the gas pipeline. The outcome of this claim is not currently determinable, however management is of the view that no payments will be made, other than defense costs, as a result of the claim. Any settlement that should arise will be accounted for in the year that a liability is established.

24 Comparative financial information

Certain prior period financial information has been amended to conform to the current period presentation.

Integrated Grain Processors Co-operative Inc.

Consolidated Financial Statements
September 30, 2010

PRICEWATERHOUSECOOPERS

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December 13, 2010

Auditors' Report

To the Shareholders of
Integrated Grain Processors Co-operative Inc.

We have audited the consolidated balance sheet of **Integrated Grain Processors Co-operative Inc.** (the "Co-operative") as at September 30, 2010 and the consolidated statements of operations and retained earnings (deficit), and cash flows for the year then ended. These financial statements are the responsibility of the Co-operative's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Co-operative as at September 30, 2010 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Integrated Grain Processors Co-operative Inc.
Consolidated Balance Sheet
As at September 30, 2010

	2010 $	2009 $
Assets (note 7)		
Current assets		
Cash	14,180,256	7,540,769
Restricted cash (note 3)	3,707,130	4,699,344
Accounts receivable (note 4)	10,534,594	14,536,345
Inventory (note 5)	4,088,165	3,499,728
Prepaid expenses and deposits (note 14)	3,164,335	1,658,334
Fair value of commodity derivative contracts (note 13)	-	226,501
Future income taxes	628,000	549,000
	36,302,480	32,710,021
Property, plant and equipment (note 6)	79,829,439	85,947,990
Intangible assets	2,996,803	3,227,324
Future income taxes	1,521,000	336,000
	120,649,722	122,221,335
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	3,555,220	6,905,236
Income taxes payable	540,517	87,000
Fair value of commodity derivative contracts (note 13)	898,991	-
Fair value of interest rate swap contracts (note 18)	1,436,240	2,042,963
Current portion of capital lease obligation (note 8)	539,670	464,433
Current portion of subordinated debentures and notes (note 9)	731,544	-
Current portion of term debt (note 7)	5,150,000	7,337,688
	12,852,182	16,837,320
Capital lease obligation (note 8)	3,186,383	3,726,053
Subordinated debentures and notes (note 9)	1,107,000	2,384,500
Term debt (note 7)	29,336,112	42,625,314
Research and development fund liability (note 15)	1,821,261	1,708,500
Future income taxes	6,285,000	1,160,000
	54,587,938	68,441,687
Shareholders' Equity		
Capital stock (note 10)	52,966,860	53,036,960
Contributed surplus (note 20)	806,150	906,150
Retained earnings (deficit)	12,288,774	(163,462)
	66,061,784	53,779,648
	120,649,722	122,221,335

Approved by the Board of Directors

_______________ Director _______________ Director

Integrated Grain Processors Co-operative Inc.

Consolidated Statement of Operations and Retained Earnings (Deficit)

For the year ended September 30, 2010

	2010 $	2009 $
Net sales	94,572,758	89,382,111
Cost of goods sold	86,862,984	91,209,893
Depreciation and amortization	6,584,951	6,309,950
Net loss (gain) on commodity derivative contracts	1,914,480	(36,746)
Operating grants (note 15)	(27,116,164)	(26,835,865)
	68,246,251	70,647,232
Gross profit	26,326,507	18,734,879
Selling, general and administrative expenses	4,191,364	3,396,720
Amortization of deferred financing costs and depreciation	1,570,667	1,948,324
	5,762,031	5,345,044
Operating income	20,564,476	13,389,835
Other income (expenses)		
Interest expense (note 16)	(4,184,054)	(5,622,995)
Interest income	33,780	48,640
Gain (loss) on interest rate swap (note 18)	606,724	(758,096)
Loss on foreign exchange	(79,690)	(48,847)
	(3,623,240)	(6,381,298)
Income before provision for taxes	16,941,236	7,008,537
Provision for current income taxes	628,000	87,000
Provision for future income taxes	3,861,000	2,190,000
	4,489,000	2,277,000
Net income for the year	12,452,236	4,731,537
Deficit - Beginning of year	(163,462)	(4,894,999)
Retained earnings (deficit) - End of year	12,288,774	(163,462)

Integrated Grain Processors Co-operative Inc.

Consolidated Statement of Cash Flows

For the year ended September 30, 2010

	2010 $	2009 $
Cash flows from operating activities		
Net income for the year	12,452,236	4,731,537
Changes (credits) to income not involving cash:		
Depreciation and amortization	8,155,618	8,258,274
Unrealized (gain) loss on commodity derivative contracts	1,125,492	(226,501)
(Gain) loss on interest rate swap contracts	(606,723)	758,096
Interest on research and development fund liability	112,761	54,579
Future income taxes	3,861,000	2,190,000
	25,100,384	15,765,985
Net change in non-cash working capital balances (note 19)	(989,186)	(3,748,711)
	24,111,198	12,017,274
Cash flows from financing activities		
Repayments of subordinated debentures and notes (note 9)	(545,956)	(62,500)
Net proceeds and redemptions of share subscriptions (note 10)	(70,100)	827,000
Settlement of stock options (note 20)	(100,000)	-
Proceeds from credit facility (note 7)	-	18,711,156
Payment of bridge facility (note 7)	-	(14,000,000)
Payment of term debt (note 7)	(16,971,188)	(9,728,812)
Payment of capital lease obligation (note 8)	(464,433)	(404,708)
Deferred financing costs (note 7)	-	(36,368)
Decrease in restricted cash (note 3)	992,214	2,219,479
	(17,159,463)	(2,474,753)
Cash flows from investing activities		
Purchase of property and equipment	(312,248)	(959,121)
Construction in progress	-	(18,315,894)
Proceeds from OMAFRA capital grant (note 15)	-	14,000,000
	(312,248)	(5,275,015)
Net increase in cash	6,639,487	4,267,506
Cash - Beginning of year	7,540,769	3,273,263
Cash - End of year	14,180,256	7,540,769

1 Nature of operations

Integrated Grain Processors Co-operative Inc. (the "Co-operative") was incorporated on April 4, 2002 under the Ontario Co-operative Corporations Act.

The Co-operative produces and sells ethanol and distillers grain through its 150 million litre fuel ethanol production facility in south western Ontario, which was completed on October 15, 2008.

2 Summary of significant accounting policies

Principles of consolidation

The consolidated financial statements include the financial statements of the Co-operative and its wholly-owned subsidiary, IGPC Ethanol Inc. (the "Subsidiary"). Intercompany balances and transactions have been eliminated on consolidation.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the year reported. Actual results could differ from those estimates.

Revenue recognition

The Co-operative recognizes revenue on the sale of ethanol and distillers grains at the time of shipment.

Government assistance

Government grants are recognized when there is reasonable assurance that the Co-operative has complied with the conditions of the grant. Such grants are accounted for as reduction of the related expense or asset, or as income, as appropriate.

Inventories

Inventories of finished products, feedstock, process chemicals and supplies are valued at the lower of net realizable value and average cost. Work in process consists of cost of material and direct labour and is valued at the lower of net realizable value and average cost.

Property, plant and equipment

Property, plant and equipment are stated at cost. Amortization is provided for in the accounts as follows:

Buildings and site pipelines	5% declining balance
Furniture and fixtures	20% declining balance
Equipment	30% declining balance
Process equipment	15 years straight line
Gas pipeline under capital lease	7 years straight line

In the year of acquisition, amortization is provided for at one-half of the above rates, except in 2009 when the cost of the process plant was transferred from construction in progress to the appropriate asset categories and amortization was provided for from the date of production. No amortization is provided for in the year of disposal or until assets are put into service.

The total cost of major capital projects includes related interest incurred during the period of construction. Capitalization of interest ceased on October 15, 2008 when the ethanol plant was substantially complete and ready for its intended productive use.

Grants under government capital assistance programs are deducted from the cost of the assets to which the grant relates.

Intangible asset

The intangible asset recorded on the balance sheet, relates to the right to use the proprietary design and processes to produce ethanol. The asset is being amortized over the life of the process equipment of 15 years.

Financial instruments

Under CICA Handbook Section 3855 - *Financial Assets and Liabilities*, including derivative instruments, are initially recognized and subsequently measured based on their classification as held-for-trading, available-for-sale financial assets, held-to-maturity, loans and receivables, or other financial liabilities as follows:

- Held-for-trading financial instruments are measured at their fair value with changes in fair value recognized in net income for the year.
- Available-for-sale financial assets are measured at their fair value and changes in fair value are included in other comprehensive income until the asset is removed from the balance sheet.
- Loans and receivables are measured at cost or amortized cost using the effective interest rate method.
- Other financial liabilities are measured at cost or amortized cost using the effective interest rate method
- Derivative instruments, including embedded derivatives, are measured at their fair value with changes in fair value recognized in net income for the year unless the instrument is a cash flow hedge and

hedge accounting applies in which case changes in fair value are recognized in other comprehensive income.

The following is a summary of the classification of assets and liabilities of the Co-operative:

Financial Instrument	**Classification**
Cash	Held-for-trading
Restricted cash	Held-for-trading
Accounts receivable	Loans and receivables
Fair value of commodity derivative contracts	Derivative instrument (non-hedge)
Accounts payable and accrued liabilities	Other financial liabilities
Fair value of interest rate swap contracts	Derivative instrument (non-hedge)
Capital lease obligation	Other financial liabilities
Subordinated debentures and notes	Other financial liabilities
Term and bank debt	Other financial liabilities
Research and development fund liability	Other financial liabilities

As a co-operative business enterprise, the Co-operative has elected to apply CICA Handbook Section 3861 - *Financial Instruments - Disclosures and Presentation,* in lieu of CICA Handbook Section 3862 - *Financial Instruments - Disclosure*, and 3863 - *Financial Instruments - Presentation.* CICA Handbook Section 3861 specifies the presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed about them.

Deferred financing costs

Transaction costs related to the credit agreement are netted against the carrying value of the term loan and are amortized over the duration of the credit agreement using the effective interest rate method, based on target debt levels of the term loan and expected levels of available credit under the revolving term facility.

Interest rate swap contracts

Exposure to interest rates on debt is managed through the use of interest rate swap contracts. These swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Settlement amounts under interest rate swap contracts have been included in capitalized interest during the pre-operating period prior to October 15, 2008. Changes in the fair value of the interest rate swap contracts have been recorded in the statement of operations.

Stock options

Options are accounted for under the fair market method. Stock-based compensation costs, measured at the grant date based on the fair value of the options granted and recognized over the service period involved, are recorded as expenses on the income statement. The amounts are credited to contributed surplus. The consideration paid upon exercise of the options and the originally recorded fair value of the options are added to share capital.

Income taxes

The liability method of accounting for income taxes is used. Under this method, future income tax assets and liabilities are determined based on the differences between the carrying amount of assets and liabilities and the tax cost bases of these assets and liabilities measured using substantially enacted income tax laws and rates.

Future accounting recommendations

Business combinations

CICA Handbook Section 1582 - *Business Combinations*, will improve the relevance, reliability and comparability of the information that a reporting entity provides in its financial statements about a business combination and its effects. This section outlines a variety of changes, including but not limited to the following: an expanded definition of a business, a requirement to measure all business combinations and non-controlling interest at fair value and a requirement to recognize future income tax assets and liabilities and acquisition and related costs as expenses of the period. The standard is effective for fiscal periods beginning on or after January 1, 2011. The Co-operative is currently reviewing the impact of this standard and will adopt the standard commencing in fiscal 2012.

Consolidated financial statements and non-controlling interests

CICA Handbook Sections 1601 - *Consolidated Financial Statements*, and 1602 - *Non-controlling Interests*, will replace CICA Handbook Section 1600 - *Consolidated Financial Statements*. Section 1601 establishes standards for the preparation of consolidated financial statements and specifically addresses consolidation accounting following a business combination that involves the purchase of an equity interest in one company by another. Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard is effective for fiscal periods beginning on or after January 1, 2011. The Co-operative is currently reviewing the impact of this standard and will adopt the standard commencing in fiscal 2012.

Future accounting standards

Non-publicly accountable enterprises have the option of adopting International Financial Reporting Standards (IFRS) or Accounting Standards for Private Enterprises (ASPE) for annual financial statements for fiscal years beginning on or after January 1, 2011. Management and the Board of Directors have determined that the Co-operative will adopt IFRS for its fiscal year ending September 30, 2012. Management is in the process of determining the impact of this change on its accounting policies and reporting practices.

3 Restricted cash

	2010 $	2009 $
Debt service reserve account	3,497,575	4,484,689
Post completion account	209,555	214,655
	3,707,130	4,699,344

Under the terms of the credit agreement, as construction funds were obtained, a portion was added to the debt service reserve account such that at substantial completion the sum of two principal instalments plus six months of interest is available in a separate account to service bank debt. In the event cash flow is insufficient to meet the quarterly requirement, these funds may be used but must be replenished.

4 Accounts receivable

	2010 $	2009 $
Trade accounts receivable	2,058,381	1,129,194
Operating grants receivable (note 15)	8,403,816	5,891,353
Capital grant receivable (note 15)	-	7,277,514
Other receivables	72,397	238,284
	10,534,594	14,536,345

5 Inventory

	2010 $	2009 $
Fuel grade ethanol	925,550	1,354,698
Work in process	1,143,096	946,517
Feedstock, process chemicals and supplies	2,019,519	1,198,513
	4,088,165	3,499,728

6 Property, plant and equipment

			2010
	Cost $	Accumulated Amortization $	Net $
Land	2,923,721	-	2,923,721
Buildings	13,648,830	1,296,645	12,352,185
Site pipelines	2,287,513	237,440	2,050,073
Furniture and fixtures	75,703	28,463	47,240
Equipment	715,077	311,914	403,163
Process equipment	64,575,452	8,574,220	56,001,232
Gas pipeline under capital lease (note 8)	8,472,554	2,420,729	6,051,825
	92,698,850	12,869,411	79,829,439

			2009
	Cost $	Accumulated Amortization $	Net $
Land	2,923,721	-	2,923,721
Buildings	13,615,335	647,412	12,967,923
Site pipelines	2,287,513	129,541	2,157,972
Furniture and fixtures	70,228	17,337	52,891
Equipment	621,364	159,211	462,153
Process equipment	64,395,889	4,274,	60,121,141
Gas pipe line under capital lease (note 8)	8,472,554	1,210,364	7,262,189
	92,386,604	6,438,614	85,947,990

In the prior year, the Co-operative received and recognised capital grants from the Government for plant construction costs in the amount of $19,623,593, which are netted against the total cost of the ethanol plant.

7 Term debt

	2010 $	2009 $
Term debt	37,000,000	53,971,188
Less: Current portion	(5,150,000)	(7,377,688)
Less: Deferred financing costs	(2,513,888)	(4,008,186)
	29,336,112	42,625,314

The Co-operative entered into a credit agreement on June 15, 2007 with a lead bank as Agent for certain lenders to initially make the following credit facilities available:

a) A seven year non-revolving term loan facility for $63,700,000 to be used for construction of the plant with principal payments of $3,822,000 commencing in 2009, due June 27, 2014.

b) Certain non-revolving bridge facilities for construction costs prior to receipt of government funding in the amount of $14,000,000.

c) A seven year revolving term facility for working capital purposes not to exceed lesser of $7,000,000 or the borrowing base. Borrowing base uses as collateral 85% of eligible receivables and inventory. Subsequently to year end, the amount has been reduced to $6,000,000.

In the prior year, the Co-operative had drawn the full amount allowed against the seven year non-revolving term loan facility. The revolving facility became available after substantial completion of the ethanol plant as defined under the credit agreement.

The credit agreement also provided a short-term bridge facility for $14,000,000 which was repaid in March 2009 when the Co-operative received the $14,000,000 capital grant from OMAFRA (note 15).

Deferred financing costs have been allocated to the term loan, revolving term facility and bridge facility. At year-end the unamortized balances allocated to these elements of the credit agreement are $1,933,088 (2009 - $3,233,786), $580,800 (2009 - $744,400) and Nil (2009 - Nil) respectively.

As at September 30, 2010, the Co-operative had $2,754,481 (2009 - $2,754,481) of letters of credit drawn against the seven year revolving term facility.

During construction, interest was based on the variable banker's acceptance rate and a stamping fee of 3.75%. After substantial completion, the debt became a term debt with interest at the variable banker's acceptance rate and a stamping fee of 3.25% which was increased to 4.00% after negotiating the amendment to the credit agreement. The aggregate amount of principal payments required in each of the next four years under debt facilities are:

	$
2011	5,150,000
2012	11,581,818
2013	11,581,818
2014	8,686,364
	37,000,000

Debt repayments made on each repayment date has been the greater: of 70% of excess cash flows; and the difference between the outstanding amount and the target outstanding debt to a maximum of 100% of the excess cash flows. The target outstanding debt is reduced by $2,895,455 per quarter. If there are no excess cash flows, the Co-operative is required to pay 1.5% of the initial debt outstanding for a total of $955,500 per quarter, which has been disclosed in the principal payments required above and adjusted for the target outstanding debt amount. As at September 30, 2010, the target debt outstanding was $43,431,818. A voluntary prepayment feature allows the Co-operative to prepay a minimum of $500,000 with adequate notice to the Agent.

Since the inception of the seven year revolving term facility, the Co-operative has made the following principal payments:

	$
Term debt at inception	63,700,000
Principal payments in 2009	(9,728,812)
Principal payments in 2010	(16,971,188)
	37,000,000

Under the credit agreement, the Co-operative has provided security to the lenders, the key elements of which are as follows:

a) a fixed and floating charge debenture in the amount of $150 million;
b) a general security agreement covering all assets of the Co-operative;
c) an assignment of insurance; and
d) a limited recourse guarantee and a securities pledge agreement.

8 Capital lease obligation

As part of the construction of the ethanol plant, it was necessary for the local natural gas distributor to construct a 29 km pipeline from a Union Gas trunk pipeline to the town of Aylmer. The costs of the pipeline are fully borne by the Co-operative, through 'aid-to-construct' payments, plus certain fixed gas delivery charges over a 7 year contract period. While the Co-operative has no ownership interest in the pipeline, accounting guidelines require that in such instances where the value of the asset is fully recovered by the supplier and the customer has exclusive, or virtually exclusive, use of the asset, the arrangement is accounted for as a lease.

Accordingly, the Co-operative has recorded the capital cost of the pipeline as a capital lease, and the discounted value of certain fixed gas delivery charges over the next 7 years as a capital lease obligation, with notional interest of 15%. The details of the capital lease obligation are as follows:

Future minimum lease payments:	$
2011	1,066,252
2012	1,066,252
2013	1,066,252
2014	1,066,252
2015	1,066,252
	5,331,260
Amounts representing interest	1,605,207
	3,726,053
Less: Current portion	539,670
Long-term portion	3,186,383

In addition to the foregoing, the Co-operative is obligated to provide a letter of credit to the natural gas distributor to ensure performance under the agreement. At year end, a letter of credit in the amount of $5,214,173 (2009 - $5,214,173) was issued in their favour.

The final cost of the pipeline is currently under review by the Ontario Energy Board. Should the final costs differ from costs determined for purposes of calculating the capital lease obligation, the obligation will be adjusted accordingly.

9 Subordinated debentures and notes

	2010 $	2009 $
Class A debentures maturing on December 31, 2013 and bearing interest at 8.5% per annum	1,070,000	1,070,000
Class B debentures maturing on December 31, 2013 and bearing interest at 7.5% per annum	37,000	37,000
Promissory notes maturing on December 31, 2010 and bearing interest at 8% per annum	731,544	1,277,500
	1,838,544	2,384,500
Less: Current portion	731,544	-
	1,107,000	2,384,500

The redemption of these subordinate debentures at maturity and the payment of interest thereon are subject to the prior consent of the lenders to the subsidiary.

10 Capital stock

Authorized

Prior to June 8, 2010:

100,000 membership shares, voting, with a par value of $100 each.

11,000,000 Class A preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class B preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class C preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class D preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class A and Class B preference shares are redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately preceding fiscal year subject to certain conditions. The Class C and D preference shares are redeemable at their par value. The preference shares do not carry a retraction right.

Each of the Class A, B, C, and D preference shares is entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

With effect from June 8, 2010:

100,000 membership shares, voting, with a par value of $100 each.

20,000,000 Class E preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class E preference shares are redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately preceding fiscal year subject to certain conditions, plus a pro rata share of such premiums as may have been paid upon the purchase of any Class E preference shares. The preference shares do not carry a retraction right.

Each of the Class E preference shares is entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

In the prior year, 30 membership shares, 168,000 Class A preference shares and 1,000 Class B preference shares were issued for cash consideration of $3,000, $840,000 and $5,000 respectively.

During the year, all Class C and D preference shares were redeemed in full and all Class B preference shares were re-designated as Class A preference shares on a one to one basis. After which, all Class A preference shares were renamed as Class E preference shares. The Class A, B, C and D preference shares were deleted in the articles of amendment dated June 8, 2010, leaving only the membership shares and Class E preference shares authorized and issued at year end. These changes were approved by the members of the Co-operative at the Annual General Meeting on March 25, 2010.

Issued and fully paid	Membership		Class E (Class A prior to June 8, 2010)		Class B		Class C		Class D		Total
	#	$	#	$	#	$	#	$	#	$	$
Issued at October 1, 2008	4,235	423,500	10,270,359	50,766,795	194,713	973,565	800	4,000	8,420	42,100	52,209,960
New subscriptions	30	3,000	168,000	840,000	1,000	5,000	-	-	-	-	848,000
Redemptions	(10)	(1,000)	-	-	(4,000)	(20,000)	-	-	-	-	(21,000)
Balance, September 30, 2009	4,255	425,500	10,438,359	51,606,795	191,713	958,565	800	4,000	8,420	42,100	53,036,960
New subscriptions	-	-	-	-	2,000	10,000	-	-	-	-	10,000
Redemptions	(15)	(1,500)	(2,900)	(14,500)	(3,600)	(18,000)	(800)	(4,000)	(8,420)	(42,100)	(80,100)
Re-designation of Class B shares as Class E shares	-	-	190,113	950,565	(190,113)	(950,565)	-	-	-	-	-
Balance, September 30, 2010	4,240	424,000	10,625,572	52,542,860	-	-	-	-	-	-	52,966,860

11 Capital disclosures

The Co-operative has two primary capital management objectives. The first of which is to raise and maintain a capital base to finance the construction and operation of an ethanol manufacturing facility. In compliance with the credit agreement, membership and preference shares and subordinate debentures ("securities") have been issued. These securities are governed by the Co-operative Corporations Act. Annually, an Offering Statement is filed with the Superintendent (Financial Services Corporation of Ontario).

The second primary capital management objective is to safeguard the Co-operative's ability to continue as a going concern so that it can provide returns to its shareholders and benefits for other stakeholders. In this context, management considers capital to be its net worth as defined in the credit agreement as containing shareholders' equity and capital grants. The agent for the syndicate of the term debt has imposed certain covenants in connection with the term debt and credit facilities. As at September 30, 2010, the Co-operative was in compliance with these covenants.

12 Financial instruments

Fair value

The fair value of financial instruments, such as cash, restricted cash, accounts receivable, and accounts payable and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Commodity derivative contracts and the interest rate swap contract are carried at fair value.

The research and development fund liability has been recorded at fair value at the time of recognition and is carried at amortized cost (note 15).

Management has not determined the fair value of its bank debt, capital lease obligations or subordinated debentures and notes.

Credit risk

The Co-operative's exposure to credit risk relates to its accounts receivable. Due to the exclusive marketing arrangements for ethanol and distillers grains, all of the trade accounts receivables are with two customers.

Interest rate risk

The Co-operative is exposed to fluctuations in interest rates on its cash, restricted cash, and term debt. A portion of this risk due to variable interest rates has been addressed by the use of interest rate swap contracts (note 18).

13 Commodity derivative contracts

The Co-operative is exposed to the impact of market fluctuations associated with commodity prices. It anticipates the use of derivative financial instruments as part of an overall strategy to manage market risk, assuming it has sufficient liquidity to manage such a strategy. The Co-operative intends, when able, to use cash, futures, swaps, costless collars and option contracts to mitigate against the risk of changes to the commodity prices of corn, natural gas and ethanol. The Co-operative will not enter into these derivative financial instruments for trading or speculative purposes, nor will it designate these contracts as cash flow or fair value hedges for accounting. These financial instruments are accounted for using the mark-to-market method, with any changes in fair value immediately recognized in operations.

At September 30, 2010, the Co-operative had the following derivative contracts outstanding:

	Average cost/price in USD	Expiry
Corn	$4.02 - $5.22/bushel	Dec 2010 – Mar 2011
Ethanol	$1.62/US gallon	Oct 2010 – Apr 2011
Natural gas	$4.50 - 6.00/MMBtu	Nov 2010 – Mar 2011
RBOB*	$1.945/US gallon	Oct 2010

The net market value of these open positions is an unrealized loss of $898,991 (2009 - gain of $226,501).

(* RBOB – reformulated gasoline blendstock for oxygenate blending)

14 Commitments

Corn supply agreement

The Co-operative has entered into an exclusive agreement for the supply of corn for production of ethanol for an initial term of five years from October 1, 2008, and it is expected that 400,000 metric tonnes are to be supplied each year. The Co-operative is also required under the agreement to provide adequate assurance for the corn supplier's mark-to-market exposure over a pre-determined threshold. At year end, the Co-operative had deposited $500,000 (2009 - $Nil) with the corn supplier with respect to this commitment, and this amount is recorded in prepaid expenses and deposits.

Risk management agreement

The Co-operative has entered into an agreement with a risk management services provider to implement an integrated price risk management program for an initial term of one year from June 22, 2007 and is automatically renewed each year for an additional one year term.

Ethanol marketing agreement

The Co-operative has entered into an exclusive agreement with an ethanol marketer for the marketing of all of the ethanol production for an initial term of one year from the first day of production, which was October 15, 2008, and the agreement has been renewed for an additional two year term. The ethanol marketing company has agreed to take and pay for 100% of the output.

Distillers grain purchaser agreement

The Co-operative has entered into an exclusive agreement with a marketer to market the following by-products of ethanol production: dry grains with solubles, wet grains with solubles, and wet modified grains with solubles for an initial term of five years from the first day of production, which was October 15, 2008.

15 Government grants

Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA)

The Co-operative has been awarded two grants from OMAFRA:

a) In March 2009, the Co-operative received a capital grant of $14,000,000 after completion of the project and achieving nameplate capacity by establishing the capability of producing 145 million litres of ethanol in a calendar year. As a condition precedent to receiving the grant, the Co-operative is committed to contribute $2,800,000 over ten years to a future industry related Research and Development Fund, as administered by the Agricultural Research Institute of Ontario. The first payment is to be made on April 1, 2012, three years after the full grant was received. An amount of $1,653,921, representing the present value of these payments discounted at 6.6%, was recorded as a research and development fund liability, thus reducing the amount of capital grant recognized for the purpose of recording the net cost of capital assets. At year end, the balance of this obligation was $1,821,261 (2009 - $1,708,500).

b) An operating grant was activated when the plant began operation in October 2008. Funding is based on the actual volume of denatured ethanol produced in a month times the rate of payment for that month (not to exceed $0.11 per litre) subject to an annual maximum of 145 million litres. During the year, the Co-operative reached this maximum and earned $10,822,542 (2009 - $12,700,695) in operating grants (2010 - $0.0746 per litre, 2009 - $0.0876 per litre), of which $1,868,872 (2009 - $1,895,591) has been accrued as an amount receivable. The agreement is set to expire December 31, 2016.

If the profitability of the Co-operative reaches or exceeds the threshold of 17.5% as calculated by the internal rate of return on a cash flow basis, the grant is reduced by 40%. This reduction increases incrementally up to 100% if profitability remains above 17.5%. As at September 30, 2010, the Co-operative's internal rate of return was below the threshold of 17.5%.

Ethanol Expansion Program contribution

This capital grant, managed by NRCan (Natural Resources Canada), has reimbursed $11,900,000 of construction costs for the ethanol facility.

For each of the calendar years from 2009 to 2016 inclusive or until the grants have been repaid in full, the company must repay an amount calculated as of December 31 of each year as follows:

> (Average Gross Income per Litre minus $0.20 per litre) X the total Fuel Ethanol Produced in the previous twelve (12) months X 0.20

If the average gross income per litre is $0.20 or less, the repayment will be zero.

ecoEnergy for Biofuels

The Co-operative qualified for an operating grant under the Federal Government's ecoEnergy for Biofuels program, managed by NRCan. The operating grant is payable quarterly, from 2008 to 2016. The maximum incentive rate payable declines from $0.10 per litre of ethanol sold in the first year to $0.04 per litre in the last. The maximum eligible sales volume is 162,000,000 litres per year. During the year, the Co-operative earned $16,293,622 (2009 - $14,135,170) in operating grants (2010 - $0.0957 per litre, 2009 - $0.0957 per litre) of which $6,534,944 (2009 - $3,995,762) has been accrued as an amount receivable.

EcoAgriculture Biofuels Capital Program contribution

On March 27, 2009 Agriculture and Agri-Food Canada signed an amendment to the agreement which increased the grant to $6,087,514. The grant is based on eligible project costs and maintaining a minimum level of investment in its parent by agriculture producers. This grant was received during the year.

16 Interest

	2010 $	2009 $
Term debt	2,122,255	3,455,030
Settlement interest on swap	1,108,995	1,104,861
Subordinated debentures and notes	163,755	218,996
Other	187,232	382,052
Capital lease obligation	601,817	666,566
	4,184,054	5,827,505
Less: Capitalized interest	-	204,510
Net interest expense	4,184,054	5,622,995

17 Income taxes

The Co-operative has non-capital losses available of $1,398,308 (2009 – $1,240,845) expiring between 2027 and 2030 that may only be offset against future taxable income. Non-capital losses can be carried forward for 20 years. In addition, the Co-operative has capital losses available for carry-forward of $736,539 (2009 – $736,539) that may be offset against future capital gains. These losses have no expiry date. The Co-operative has recognized the benefit of the non-capital losses as these are expected to be recovered, while the benefit of the capital loss has not been recognized.

18 Interest rate swap contracts

Under the terms of the credit agreement, on August 30, 2007, the Co-operative entered into monthly interest rate swap contracts to match the construction drawdown and term debt repayment schedule. These swap agreements convert a portion of the variable-rate liability into a fixed-rate liability. At September 30, 2010, the unrealized loss on these interest rate swap agreements was $1,436,240 (2009 - $2,042,963).

Terms of the agreement at September 30, 2010 are as follows:

Termination date:	June 1, 2014
Notional amount of principal (maximum):	$21,175,909 (2009 - $27,506,818)
Fixed paying rate:	4.91%

19 Net change in non-cash working capital balances

	2010 $	2009 $
(Increase) decrease in -		
Accounts receivable	4,001,751	(7,151,473)
Inventories	(588,437)	(159,800)
Prepaid expenses and deposits	(1,506,001)	(43,670)
Increase (decrease) in -		
Accounts payable and accrued liabilities	(3,350,016)	3,606,232
Income taxes payable	453,517	-
	(989,186)	(3,748,711)
Cash paid (received) during the year for:		
Interest paid	4,183,568	4,295,943
Interest received	(33,780)	(54,302)
Income taxes	87,483	-

20 Stock options

Integrated Grain Processors Co-operative Inc. is authorized to grant certain directors options to purchase Class E (Class A prior to June 8, 2010) preference shares of the Co-operative. The Co-operative, in a prior year, authorized $695,300 worth of Class A preference share options to certain directors for services provided prior to substantial completion of the ethanol plant which occurred on October 15, 2008.

These options vest when exercised and under the Co-operative Corporations Act are exercisable at $5.00 per share until they expire on June 24, 2017. They will be deemed to have been automatically exercised immediately before any change in control of the Co-operative or before the sale of substantially all of its assets.

The Co-operative had also, in a prior year, authorized $99,500 worth of Class A preference share options and $500 worth of membership share options to a non-employee for services provided leading up to obtaining financing. During the year, these options were settled with a cash payment of $100,000.

	2010 $	2009 $
Options granted to acquire 139,060 Class E (Class A prior to June 8, 2010) preference shares to directors	695,300	695,300
Options granted to acquire 19,900 Class A preference shares to a supplier	-	99,500
Options granted to acquire 5 membership shares to a supplier	-	500
Total stock options – end of year	695,300	795,300

21 Contingencies

The Co-operative has been named as a defendant in a lawsuit arising from the construction of the gas pipeline. The outcome of this claim is not currently determinable, however management is of the view that no payments will be made, other than defense costs, as a result of the claim. Any settlement that should arise will be accounted for in the year that a liability is established.

22 Statutory information

The remuneration of directors, as defined by the Co-operative Corporation Act R.S.O. 1990, Chapter C.35 is $223,704 (2009 - $258,391).

23 Comparative financial information

Certain prior period financial information has been amended to conform to the current period presentation.

Integrated Grain Processors Co-operative Inc.

Consolidated Financial Statements
September 30, 2011

PricewaterhouseCoopers LLP
Chartered Accountants
465 Richmond Street, Suite 300
London, Ontario
Canada N6A 5P4
Telephone +1 519 640 8000
Facsimile +1 519 640 8015

December 13, 2011

Independent Auditor's Report

**To the Shareholders of
Integrated Grain Processors Co-operative Inc.**

We have audited the accompanying consolidated financial statements of Integrated Grain Processors Co-operative Inc. and its subsidiary, which comprise the consolidated balance sheet as at September 30, 2011 and the consolidated statements of operations and retained earnings and cash flows for the year then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Integrated Grain Processors Co-operative Inc. and its subsidiary as at September 30, 2011 and the results of their operations and their cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Integrated Grain Processors Co-operative Inc.
Consolidated Balance Sheet
As at September 30, 2011

	2011 $	2010 $
Assets (note 7)		
Current assets		
Cash	17,656,630	14,180,256
Restricted cash (note 3)	2,708,217	3,707,130
Accounts receivable (note 4)	6,763,620	10,534,594
Inventory (note 5)	5,575,966	4,088,165
Prepaid expenses and deposits (note 14)	1,555,500	3,164,335
Income taxes recoverable	229,636	-
Future income taxes	1,511,000	628,000
	36,000,569	36,302,480
Property, plant and equipment (note 6)	74,504,491	79,829,439
Intangible assets	2,766,284	2,996,803
Future income taxes	835,000	1,521,000
	114,106,344	120,649,722
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	4,380,326	3,555,221
Income taxes payable	-	540,517
Fair value of commodity derivative contracts (note 13)	100,662	898,991
Fair value of interest rate swap contracts (note 18)	944,838	1,436,240
Current portion of capital lease obligation (note 8)	619,905	539,670
Current portion of subordinated debentures and notes (note 9)	-	731,544
Current portion of term debt (note 7)	3,822,000	5,150,000
Current portion of research and development fund liability (note 15)	280,000	-
	10,147,731	12,852,183
Capital lease obligation (note 8)	2,566,478	3,186,383
Subordinated debentures and notes (note 9)	1,107,000	1,107,000
Term debt (note 7)	16,393,645	29,336,112
Research and development fund liability (note 15)	1,661,464	1,821,261
Future income taxes	9,718,000	6,285,000
	41,594,318	54,587,939
Shareholders' Equity		
Capital stock (note 10)	47,788,960	52,966,860
Contributed surplus (note 20)	703,186	806,150
Retained earnings	24,019,880	12,288,773
	72,512,026	66,061,783
	114,106,344	120,649,722

Commitments (note 14)
Contingencies (note 21)

Approved by the Board of Directors

_______________ Director

_______________ Director

Integrated Grain Processors Co-operative Inc.

Consolidated Balance Sheet

As at September 30, 2011

	2011 $	2010 $
Net sales	124,689,093	94,572,758
Cost of goods sold	122,812,566	86,862,984
Depreciation and amortization	6,594,380	6,584,951
Net loss on commodity derivative contracts	1,056,061	1,914,480
Operating grants (note 15)	(28,695,041)	(27,116,164)
	101,767,966	68,246,251
Gross profit	22,921,127	26,326,507
Selling, general and administrative expenses	3,961,433	4,191,364
Amortization of deferred financing costs and depreciation	1,306,573	1,570,667
	5,268,006	5,762,031
Operating income	17,653,121	20,564,476
Other income (expenses)		
Interest expense (note 16)	(3,060,457)	(4,184,054)
Interest and other income	52,207	33,779
Gain on interest rate swap (note 18)	491,402	606,724
Gain (loss) on foreign exchange	251,134	(79,690)
	(2,265,714)	(3,623,241)
Income before provision for taxes	15,387,407	16,941,235
Provision for current income taxes	420,300	628,000
Provision for future income taxes	3,236,000	3,861,000
	3,656,300	4,489,000
Net income for the year	11,731,107	12,452,235
Retained earnings (deficit) - Beginning of year	12,288,773	(163,462)
Retained earnings - End of year	24,019,880	12,288,773

Integrated Grain Processors Co-operative Inc.

Notes to Consolidated Financial Statements
September 30, 2011

	2011 $	2010 $
Cash provided by (used in)		
Operating activities		
Net income for the year	11,731,107	12,452,235
Changes (credits) to income not involving cash		
Depreciation and amortization	7,900,953	8,155,618
Unrealized (gain) loss on commodity derivative contracts	(798,329)	1,125,492
Gain on interest rate swap contracts	(491,402)	(606,723)
Loss on disposal of property, plant and equipment	9,296	-
Interest on research and development fund liability	120,203	112,761
Future income taxes	3,236,000	3,861,000
	21,707,828	25,100,383
Net change in non-cash working capital balances (note 19)	3,946,960	(989,185)
	25,654,788	24,111,198
Financing activities		
Repayments of subordinated debentures and notes	(731,544)	(545,956)
Net proceeds and redemptions of share subscriptions	(8,500)	(70,100)
Return of capital	(5,247,520)	-
Settlement of stock options (note 20)	(24,844)	(100,000)
Payment of term debt (note 7)	(15,500,000)	(16,971,188)
Payment of capital lease obligation	(539,670)	(464,433)
Repayment of capital grant (note 15)	(179,021)	-
Decrease in restricted cash	998,913	992,214
	(21,232,186)	(17,159,463)
Investing activities		
Purchase of property and equipment	(988,228)	(312,248)
Proceeds from disposal of property, plant and equipment	42,000	-
	(946,228)	(312,248)
Net increase in cash	3,476,374	6,639,487
Cash - Beginning of year	14,180,256	7,540,769
Cash - End of year	17,656,630	14,180,256

1 Nature of operations

Integrated Grain Processors Co-operative Inc. (the "Co-operative") was incorporated on April 4, 2002 under the Ontario Co-operative Corporations Act.

The Co-operative produces and sells ethanol and distillers grain through its 150 million litre fuel ethanol production facility in south western Ontario, which was completed on October 15, 2008.

2 Summary of significant accounting policies

Principles of consolidation

The consolidated financial statements include the financial statements of the Co-operative and its wholly-owned subsidiary, IGPC Ethanol Inc. (the "subsidiary"). Intercompany balances and transactions have been eliminated on consolidation.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the year reported. Actual results could differ from those estimates.

Revenue recognition

The Co-operative recognizes revenue on the sale of ethanol and distillers grains at the time of shipment.

Government assistance

Government grants are recognized when there is reasonable assurance that the Co-operative has complied with the conditions of the grant. Such grants are accounted for as reduction of the related expense or asset, or as income, as appropriate.

Inventories

Inventories of finished products, feedstock, process chemicals and supplies are valued at the lower of net realizable value and average cost. Work in process consists of cost of material and direct labour and is valued at the lower of net realizable value and average cost.

Property, plant and equipment

Property, plant and equipment are stated at cost. Amortization is provided for in the accounts as follows:

Buildings and site pipelines	5% declining balance
Furniture and fixtures	20% declining balance
Equipment	30% declining balance
Process equipment	15 years straight line
Gas pipeline under capital lease	7 years straight line

In the year of acquisition, amortization is provided for at one-half of the above rates, except in 2009 when the cost of the process plant was transferred from construction in progress to the appropriate asset categories and amortization was provided for from the date of production.

The total cost of major capital projects includes related interest incurred during the period of construction. Capitalization of interest ceased on October 15, 2008 when the ethanol plant was substantially complete and ready for its intended productive use.

Grants under government capital assistance programs are deducted from the cost of the assets to which the grant relates.

Intangible asset

The intangible asset recorded on the balance sheet, relates to the right to use the proprietary design and processes to produce ethanol. The asset is being amortized over the life of the process equipment of 15 years.

Financial instruments

Under CICA Handbook Section 3855 - Financial Assets and Liabilities, including derivative instruments, are initially recognized and subsequently measured based on their classification as held-for-trading, available-for-sale financial assets, held-to-maturity, loans and receivables, or other financial liabilities as follows:

- Held-for-trading financial instruments are measured at their fair value with changes in fair value recognized in net income for the year.
- Available-for-sale financial assets are measured at their fair value and changes in fair value are included in other comprehensive income until the asset is removed from the balance sheet.
- Loans and receivables are measured at cost or amortized cost using the effective interest rate method.
- Other financial liabilities are measured at cost or amortized cost using the effective interest rate method.

- Derivative instruments, including embedded derivatives, are measured at their fair value with changes in fair value recognized in net income for the year unless the instrument is a cash flow hedge and hedge accounting applies in which case changes in fair value are recognized in other comprehensive income.

The following is a summary of the classification of assets and liabilities of the Co-operative:

Financial Instrument	**Classification**
Cash	Held-for-trading
Restricted cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other financial liabilities
Fair value of commodity derivative contracts	Derivative instrument (non-hedge)
Fair value of interest rate swap contracts	Derivative instrument (non-hedge)
Term and bank debt	Other financial liabilities
Capital lease obligation	Other financial liabilities
Shareholder loan	Other financial liabilities
Research and development fund liability	Other financial liabilities
Preference shares	Other financial liabilities

As a non-publicly accountable enterprise, the Co-operative has elected to apply CICA Handbook Section 3861 - Financial Instruments - Disclosure and Presentation, in lieu of CICA Handbook Section 3862 - Financial Instruments - Disclosure, and 3863 - Financial Instruments - Presentation. CICA Handbook Section 3861 specifies the presentation of financial instruments and non-financial derivatives, and identifies the information that should be disclosed.

Deferred financing costs

Transaction costs related to the credit agreement are netted against the carrying value of the term loan and are amortized over the duration of the credit agreement using the effective interest rate method, based on target debt levels of the term loan and expect levels of available credit under the revolving term facility.

Interest rate swap contracts

Exposure to interest rates on debt is managed through the use of interest rate swap contracts. These swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Settlement amounts under interest rate swap contracts have been included in capitalized interest during the pre-operating period prior to October 15, 2008. Changes in the fair value of the interest rate swap contracts have been recorded in the statement of operations.

Stock options

Options are accounted for under the fair market method. Stock-based compensation costs, measured at the grant date based on the fair value of the options granted and recognized over the service period involved, are recorded as expenses on the income statement. The amounts are credited to contributed surplus. The consideration paid upon exercise of the options and the originally recorded fair value of the options are added to share capital.

Income taxes

The liability method of accounting for income taxes is used. Under this method, future income tax assets and liabilities are determined based on the differences between the carrying amount of assets and liabilities and the tax cost bases of these assets and liabilities measured using substantially enacted income tax laws and rates.

Future accounting changes

Non-publicly accountable enterprises have the option of adopting International Financial Reporting Standards (IFRS) or Accounting Standards for Private Enterprises (ASPE) for annual financial statements for fiscal years beginning on or after January 1, 2011. Management and the Board of Directors have determined that the Co-operative will adopt IFRS for its fiscal year ending September 30, 2012. Management is in the process of determining the impact of this change on its accounting policies and reporting practices.

3 Restricted cash

	2011 $	2010 $
Debt service reserve account	2,708,217	3,497,575
Post completion account	-	209,555
	2,708,217	3,707,130

Under the terms of the credit agreement, as construction funds were obtained, a portion was added to the debt service reserve account such that at substantial completion the sum of two principal instalments plus six months of interest is available in a separate account to service bank debt. In the event cash flow is insufficient to meet the quarterly requirement, these funds may be used but must be replenished.

4 Accounts receivable

	2011 $	2010 $
Trade accounts receivable	2,742,211	2,058,381
Operating grants receivable (note 15)	4,016,990	8,403,816
Other receivables	4,419	72,397
	6,763,620	10,534,594

5 Inventory

	2011 $	2010 $
Fuel grade ethanol	1,903,821	925,550
Work in process	1,076,700	1,143,096
Feedstock, process chemicals and supplies	2,595,445	2,019,519
	5,575,966	4,088,165

6 Property, plant and equipment

			2011
	Cost $	Accumulated Amortization $	Net $
Land	2,923,721	-	2,923,721
Buildings	14,313,440	1,930,780	12,382,660
Site pipelines	2,287,513	339,944	1,947,569
Furniture and fixtures	93,703	39,711	53,992
Equipment	739,630	386,715	352,915
Process equipment	64,920,588	12,918,415	52,002,173
Gas pipeline under capital lease (note 8)	8,472,554	3,631,093	4,841,461
	93,751,149	19,246,658	74,504,491

			2010
	Cost $	Accumulated Amortization $	Net $
Land	2,923,721	-	2,923,721
Buildings	13,648,830	1,296,645	12,352,185
Site pipelines	2,287,513	237,440	2,050,073
Furniture and fixtures	75,703	28,463	47,240
Equipment	715,077	311,914	403,163
Process equipment	64,575,452	8,574,220	56,001,232
Gas pipe line under capital lease (note 8)	8,472,554	2,420,729	6,051,825
	92,698,850	12,869,411	79,829,439

7 Term debt

	2011 $	2010 $
Term debt	21,500,000	37,000,000
Less: Current portion	(3,822,000)	(5,150,000)
Less: Deferred financing costs	(1,284,355)	(2,513,888)
	16,393,645	29,336,112

The Co-operative entered into a credit agreement on June 15, 2007 with a lead bank as Agent for certain lenders to initially make the following credit facilities available:

a) A seven year non-revolving term loan facility for $63,700,000 to be used for construction of the plant with principal payments of $3,822,000 commencing in 2009, due June 27, 2014.

b) Certain non-revolving bridge facilities for construction costs prior to receipt of government funding in the amount of $14,000,000.

c) A seven year revolving term facility for working capital purposes not to exceed lesser of $7,000,000 or the borrowing base. Borrowing base uses as collateral 85% of eligible receivables and inventory. During the year, the amount was reduced to $6,000,000.

In 2009, the Co-operative had drawn the full amount allowed against the seven year non-revolving term loan facility. The revolving facility became available after substantial completion of the ethanol plant as defined under the credit agreement.

The credit agreement also provided a short-term bridge facility for $14,000,000 which was repaid in March 2009 when the Co-operative received the $14,000,000 capital grant from OMAFRA (note 15).

Deferred financing costs have been allocated to the term loan, revolving term facility and bridge facility. At year-end the unamortized balances allocated to these elements of the credit agreement are $897,155 (2010 - $1,933,088), $387,200 (2010 - $580,800) and Nil (2010 - Nil) respectively.

As at September 30, 2011, the Co-operative had $2,754,481 (2010 - $2,754,481) of letters of credit drawn against the seven year revolving term facility.

During construction, interest was based on the variable banker's acceptance rate and a stamping fee of 3.75%. After substantial completion, the debt became a term debt with interest at the variable banker's acceptance rate and a stamping fee of 3.25% which was increased to 4% after negotiating the amendment to the credit agreement. The aggregate amount of principal payments required in each of the next three years under debt facilities are:

	$
2012	3,822,000
2013	11,581,818
2014	6,096,182
	21,500,000

Debt repayments made on each repayment date has been the greater: of 70% of excess cash flows; and the difference between the outstanding amount and the target outstanding debt to a maximum of 100% of the excess cash flows. The target outstanding debt is reduced by $2,895,455 per quarter. If there are no excess cash flows, the Co-operative is required to pay 1.50% of the initial debt outstanding for a total of $955,500 per quarter, which has been disclosed in the principal payments required above and adjusted for the target outstanding debt amount. As at September 30, 2011, the target debt outstanding was $31,850,000 (2010 - $43,431,818). A voluntary prepayment feature allows the Co-operative to prepay a minimum of $500,000 with adequate notice to the Agent.

Since the inception of the seven year revolving term facility, the Co-operative has made the following principal payments:

	$
Term debt at inception	63,700,000
Principal payments in 2009	(9,728,812)
Principal payments in 2010	(16,971,188)
Principal payments in 2011	(15,500,000)
	21,500,000

Under the credit agreement, the Co-operative has provided security to the lenders, the key elements of which are as follows:

a) a fixed and floating charge debenture in the amount of $150,000,000;
b) a general security agreement covering all assets of the Co-operative;
c) an assignment of insurance; and
d) a limited recourse guarantee and a securities pledge agreement

8 Capital lease obligation

As part of the construction of the ethanol plant, it was necessary for the local natural gas distributor to construct a 29 km pipeline from a Union Gas trunk pipeline to the town of Aylmer. The costs of the pipeline are fully borne by the Co-operative, through 'aid-to-construct' payments, plus certain fixed gas delivery charges over a seven year contract period. While the Co-operative has no ownership interest in the pipeline, accounting guidelines require that in such instances where the value of the asset is fully recovered by the supplier and the customer has exclusive, or virtually exclusive, use of the asset, the arrangement is accounted for as a lease.

Accordingly, the Co-operative has recorded the capital cost of the pipeline as a capital lease, and the discounted value of certain fixed gas delivery charges over the next four years as a capital lease obligation, with notional interest of 15%. The details of the capital lease obligation are as follows:

Future minimum lease payments:	$
2012	1,066,252
2013	1,066,252
2014	1,066,252
2015	1,066,252
	4,265,008
Amounts representing interest	1,078,625
	3,186,383
Less: Current portion	619,905
Long-term portion	2,566,478

In addition to the foregoing, the Co-operative is obligated to provide a letter of credit to the natural gas distributor to ensure performance under the agreement. At year end, a letter of credit in the amount of $5,214,173 (2010 - $5,214,173) was issued in their favour.

The final cost of the pipeline is currently under review by the Ontario Energy Board. Should the final costs differ from costs determined for purposes of calculating the capital lease obligation, the obligation will be adjusted accordingly.

9 Subordinated debentures and notes

	2011 $	2010 $
Class A debentures maturing on December 31, 2013 and bearing interest at 8.50% per annum	1,070,000	1,070,000
Class B debentures maturing on December 31, 2013 and bearing interest at 7.50% per annum	37,000	37,000
Promissory notes maturing on December 31, 2010 and bearing interest at 8% per annum	-	731,544
	1,107,000	1,838,544
Less: Current portion	-	731,544
	1,107,000	1,107,000

The redemption of these subordinate debentures at maturity and the payment of interest thereon are subject to the prior consent of the lenders.

10 Capital stock

Authorized

Prior to June 8, 2010:

100,000 membership shares, voting, with a par value of $100 each.

11,000,000 Class A preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class B preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class C preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

5,000,000 Class D preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class A and Class B preference shares were redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately preceding fiscal year subject to certain conditions. The Class C and D preference shares were redeemable at their par value. The preference shares do not carry a retraction right.

Each of the Class A, B, C, and D preference shares were entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

With effect from June 8, 2010:

100,000 membership shares, voting, with a par value of $100 each.

20,000,000 Class E preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class E preference shares are redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately preceding fiscal year subject to certain conditions, plus a pro rata share of such premiums as may have been paid upon the purchase of any Class E preference shares. The preference shares do not carry a retraction right.

Each of the Class E preference shares is entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

In the prior year, all Class C and D preference shares were redeemed in full and all Class B preference shares were re-designated as Class A preference shares on a one to one basis. After which, all Class A preference shares were renamed as Class E preference shares. The Class A, B, C and D preference shares were deleted in the articles of amendment dated June 8, 2010, leaving only the membership shares and Class E preference shares authorized and issued at year end. These changes were approved by the members of the Co-operative at the Annual General Meeting on March 25, 2010.

Integrated Grain Processors Co-operative Inc.
Notes to Consolidated Financial Statements
September 30, 2011

Issued and fully paid

	Membership		Class E (Class A prior to June 8, 2010)		Class B		Class C		Class D		Total
	#	$	#	$	#	$	#	$	#	$	$
Issued at October 1, 2009	4,135	413,500	10,642,198	51,618,795	191,713	958,565	800	4,000	8,420	42,100	53,036,960
New subscriptions	-	-	-	-	2,000	10,000	-	-	-	-	10,000
Redemptions	(15)	(1,500)	(2,900)	(14,500)	(3,600)	(18,000)	(800)	(4,000)	(8,420)	(42,100)	(80,100)
Re-designation of Class B shares as Class E shares	-	-	190,113	950,565	(190,113)	(950,565)	-	-	-	-	-
Balance, September 30, 2010	4,120	412,000	10,829,411	52,554,860	-	-	-	-	-	-	52,966,860
New issues	5	500	-	-	-	-	-	-	-	-	500
Exercised stock options	-	-	15,624	78,120	-	-	-	-	-	-	78,120
Share conversions	-	-	1,000	5,000	-	-	-	-	-	-	5,000
Redemptions	(140)	(14,000)	-	-	-	-	-	-	-	-	(14,000)
Return of capital	-	-	-	(5,247,520)	-	-	-	-	-	-	(5,247,520)
Balance, September 30, 2011	3,985	398,500	10,846,035	47,390,460	-	-	-	-	-	-	47,788,960

11 Capital disclosures

The Co-operative has two primary capital management objectives. The first of which is to raise and maintain a capital base to finance the construction and operation of an ethanol manufacturing facility. In compliance with the credit agreement, membership and preference shares and subordinate debentures ("securities") have been issued. These securities are governed by the Co-operative Corporations Act. Annually, an Offering Statement is filed with the Superintendent (Financial Services Corporation of Ontario).

The second primary capital management objective is to safeguard the Co-operative's ability to continue as a going concern so that it can provide returns to its shareholders and benefits for other stakeholders. In this context, management considers capital to be its net worth as defined in the credit agreement as containing shareholders' equity and capital grants. The agent for the syndicate of the term debt has imposed certain covenants in connection with the term debt and credit facilities. As at September 30, 2011, the Co-operative was in compliance with these covenants.

12 Financial instruments

Fair value

The fair value of financial instruments, such as cash, restricted cash, accounts receivable, and accounts payable and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Commodity derivative contracts and the interest rate swap contract are carried at fair value.

The research and development fund liability has been recorded at fair value at the time of recognition and is carried at amortized cost (note 15).

Management has not determined the fair value of its bank debt, capital lease obligations or subordinated debentures and notes.

Credit risk

The Co-operative's exposure to credit risk relates to its accounts receivable. Due to the exclusive marketing arrangements for ethanol and distillers grains, all of the trade accounts receivables are with two customers.

Interest rate risk

The Co-operative is exposed to fluctuations in interest rates on its cash, restricted cash and term debt. A portion of this risk due to variable interest rates has been addressed by the use of interest rate swap contracts (note 18).

13 Commodity derivative contracts

The Co-operative is exposed to the impact of market fluctuations associated with commodity prices and uses derivative financial instruments as part of an overall strategy to manage market risk, assuming it has sufficient liquidity to manage such a strategy. The Co-operative uses cash, futures, swaps, costless collars and option contracts to mitigate against the risk of changes to the commodity prices of corn, natural gas and ethanol. The Co-operative will not enter into these derivative financial instruments for trading or speculative purposes, nor will it designate these contracts as cash flow or fair value hedges for accounting. These financial instruments are accounted for using the mark-to-market method, with any changes in fair value immediately recognized in operations.

At September 30, 2011, the Co-operative had the following derivative contracts outstanding:

	Average cost/price in USD	Expiry
Natural gas	$4.25 - $5.00 / MMBtu	November 2011 - December 2011

The net market value of these open positions is an unrealized loss of $100,662 (2010 - $898,991).

14 Commitments

Corn supply agreement

The Co-operative has entered into an exclusive agreement for the supply of corn for production of ethanol for an initial term of five years from October 1, 2008, and it is expected that 400,000 metric tonnes are to be supplied each year. The Co-operative is also required under the agreement to provide adequate assurance for the corn supplier's mark-to-market exposure over a pre-determined threshold. At year end, the Co-operative had deposited $Nil (2010 - $500,000) with the corn supplier with respect to this commitment, and this amount is recorded in prepaid expenses and deposits.

Risk management agreement

The Co-operative has entered into an agreement with a risk management services provider to implement an integrated price risk management program for an initial term of one year from June 22, 2007 and is automatically renewed each year for an additional one year term.

Ethanol marketing agreement

The Co-operative has entered into an exclusive agreement with an ethanol marketer for the marketing of all of the ethanol production for an initial term of one year from the first day of production, which was October 15, 2008, and the agreement has been renewed for an additional two year term. The ethanol marketing company has agreed to take and pay for 100% of the output.

Distillers grain purchaser agreement

The Co-operative has entered into an exclusive agreement with a marketer to market the following by-products of ethanol production: dry grains with solubles, wet grains with solubles, and wet modified grains with solubles for an initial term of five years from the first day of production, which was October 15, 2008.

15 Government grants

Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA)

The Co-operative has been awarded two grants from OMAFRA:

a) In March 2009, the Co-operative received a capital grant of $14,000,000 after completion of the project and achieving nameplate capacity by establishing the capability of producing 145,000,000 litres of ethanol in a calendar year. As a condition precedent to receiving the grant, the Co-operative is committed to contribute $2,800,000 over ten years to a future industry related Research and Development Fund, as administered by the Agricultural Research Institute of Ontario. The first payment is to be made on April 1, 2012, three years after the full grant was received. An amount of $1,653,921, representing the present value of these payments discounted at 6.60%, was recorded as a research and development fund liability, thus reducing the amount of capital grant recognized for the purpose of recording the net cost of capital assets. At year end, the balance of this obligation was $1,941,464 (2010 - $1,821,261).

b) An operating grant was activated when the plant began operation in October 2008. Funding is based on the actual volume of denatured ethanol produced in a month times the rate of payment for that month (not to exceed $0.11 per litre) subject to an annual maximum of 145,000,000 litres. During the current and prior year, the Co-operative reached this maximum and earned $14,918,113 (2010 - $10,822,542) in operating grants (2011 - $0.1028 per litre, 2010 - $0.0746 per litre), of which $1,818,598 (2010 - $1,868,872) has been accrued as an amount receivable. The agreement is set to expire December 31, 2016.

If the profitability of the Co-operative reaches or exceeds the threshold of 17.50% as calculated by the internal rate of return on a cash flow basis, the grant is reduced by 40%. This reduction increases incrementally up to 100% if profitability remains above 17.50%. As at September 30, 2011, the Co-operative's internal rate of return was below the threshold of 17.50%.

Ethanol Expansion Program contribution

This capital grant, managed by NRCan (Natural Resources Canada), has reimbursed $11,900,000 of construction costs for the ethanol facility.

For each of the calendar years from 2009 to 2016 inclusive or until the grants have been repaid in full, the Co-operative must repay an amount calculated as of December 31 of each year as follows:

(Average Gross Income per Litre minus $0.20 per litre) X the total Fuel Ethanol Produced in the previous twelve (12) months X 0.20

If the average gross income per litre is $0.20 or less, the repayment will be zero. During the year, the Co-operative repaid $179,021 (2010 $Nil) of this capital grant as the average gross income per litre exceeded $0.20 for calendar year 2010.

ecoEnergy for Biofuels

The Co-operative qualified for an operating grant under the Federal Government's ecoEnergy for Biofuels program, managed by NRCan. The operating grant is payable quarterly, from 2008 to 2016. The maximum incentive rate payable declines from $0.10 per litre of ethanol sold in the first year to $0.04 per litre in the last. The maximum eligible sales volume is 162,000,000 litres per year. During the current and prior years, the Co-operative reached the maximum eligible sales volume and earned $13,776,928 (2010 - $16,293,622) in operating grants (2011 - $0.0849 per litre, 2010 - $0.0957 per litre) of which $2,198,392 (2010 - $6,534,944) has been accrued as an amount receivable.

EcoAgriculture Biofuels Capital Program contribution

On March 27, 2009, Agriculture and Agri-Food Canada signed an amendment to the agreement which increased the grant to $6,087,514. The grant is based on eligible project costs and maintaining a minimum level of investment in its parent by agriculture producers. This grant was received during the fiscal 2010 year.

16 Interest

	2011 $	2010 $
Term debt	1,577,257	2,122,255
Settlement interest on swap	729,012	1,108,995
Subordinated debentures and notes	103,365	163,755
Capital lease obligation	526,584	601,817
Other	124,239	187,232
	3,060,457	4,184,054

17 Income taxes

The Co-operative has non-capital losses available for carry forward of $1,577,835 (2010 - $1,398,308) that may only be offset against future taxable income. The non-capital losses consist of $1,020,636 (2010 - $841,109) which can be carried forward for 20 years and $557,109 (2010 - $557,199) which can be carried forward for ten years. In addition, the Co-operative has capital losses available for carry-forward of $736,539 (2010 - $736,539) that may be offset against future capital gains. These losses have no expiry date. The Co-operative has recognized the benefit of the non-capital losses as these are expected to be recovered, while the benefit of the capital losses has not been recognized because the timing of the recovery is unknown.

18 Interest rate swap contracts

Under the terms of the credit agreement, on August 30, 2007, the Co-operative entered into monthly interest rate swap contracts to match the construction drawdown and term debt repayment schedule. These swap agreements convert a portion of the variable-rate liability into a fixed-rate liability. At September 30, 2011, the unrealized loss on these interest rate swap agreements was $944,838 (2010 - $1,436,240).

Terms of the agreement at September 30, 2011 are as follows:

Termination date:	June 1, 2014
Notional amount of principal (maximum):	$15,925,000 (2010 - $21,175,909)
Fixed paying rate:	4.91%

19 Net change in non-cash working capital balances

	2011 $	2010 $
(Increase) decrease in:		
Accounts receivable	3,770,974	4,001,751
Inventories	(1,487,801)	(588,437)
Prepaid expenses and deposits	1,608,835	(1,506,001)
Income taxes recoverable	(229,636)	-
Increase (decrease) in:		
Accounts payable and accrued liabilities	825,105	(3,350,015)
Income taxes payable	(540,517)	453,517
	3,946,960	(989,185)
Cash paid (received) during the year for:		
Interest paid	2,397,689	4,063,771
Interest received	(52,207)	(27,803)
Income taxes paid	1,195,000	87,483

20 Stock options

Integrated Grain Processors Co-operative Inc. is authorized to grant certain directors options to purchase Class E (Class A prior to June 8, 2010) preference shares of the Co-operative. The Co-operative, in a prior year, authorized $695,300 worth of Class A preference share options to certain directors for services provided prior to substantial completion of the ethanol plant which occurred on October 15, 2008.

These options vest when exercised and under the Co-operative Corporations Act are exercisable at $5.00 per share until they expire on June 24, 2017. They will be deemed to have been automatically exercised immediately before any change in control of the Co-operative or before the sale of substantially all of its assets.

The Co-operative had also, in a prior year, authorized $124,500 worth of Class A preference share options and $500 worth of membership share options to a non-employee for services provided leading up to obtaining financing. These options were settled with a cash payment of $25,000 in the current year and $100,000 in the prior year.

During the year, the Co-operative received $156 from the exercise of 15,624 options at $0.01 per Class E preference share. Capital stock and contributed surplus were each adjusted by $78,120 for stock-based compensation previously recorded on these exercised stock options.

	2011 $	2010 $
Options granted to acquire 139,060 Class E (Class A prior to June 8, 2010) preference shares to directors	695,300	695,300
Options exercised to acquire 15,624 Class E preference shares by directors	(78,120)	-
Total stock options - End of year	617,180	695,300

21 Contingencies

The Co-operative has been named as a defendant in a lawsuit arising from the construction of the gas pipeline. The outcome of this claim is not currently determinable, however management is of the view that no payments will be made, other than defense costs, as a result of the claim. Any settlement that should arise will be accounted for in the year that a liability is established.

22 Statutory information

The remuneration of directors, as defined by the Co-operative Corporation Act R.S.O. 1990, Chapter C.35 is $252,724 (2010 - $223,704).

23 Comparative financial information

Certain prior period financial information has been amended to conform to the current period presentation.

March 23, 2012

AUDITOR'S CONSENT

We have read the offering statement of Integrated Grain Processors Co-operative Inc. ("Co-operative") dated March 1, 2012 relating to the issue and sale of Membership Shares and Class E Preference Shares of the Co-operative. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned offering statement of our report to the shareholders of the Co-operative on the consolidated balance sheet of the Co-operative as at September 30, 2011, and the consolidated statements of operations and retained earnings and cash flows for the year then ended. Our report on the consolidated financial statements is dated December 13, 2011.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

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Integrated Grain Processors Co-operative Inc.

Consolidated Financial Statements
September 30, 2012, September 30, 2011 and October 1, 2010
(expressed in Canadian dollars)

pwc

December 12, 2012

Independent Auditor's Report

To the To the Shareholders
of Integrated Grain Processors Co-operative Inc.

We have audited the accompanying consolidated financial statements of Integrated Grain Processors Co-operative Inc. and its subsidiary, which comprise the consolidated statements of financial position as at September 30, 2012, September 30, 2011 and October 1, 2010 and the consolidated statements of operations and comprehensive income, changes in shareholders' equity and cash flows for the years ended September 30, 2012 and September 30 2011, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Integrated Grain Processors Co-operative Inc. and its subsidiary as at September 30, 2012, September 30, 2011 and October 1, 2010 and their financial performance and their cash flows for the years ended September 30, 2012 and September 30, 2011 in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Integrated Grain Processors Co-operative Inc.

Consolidated Statements of Financial Position

(expressed in Canadian dollars)

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Assets (note 9)			
Current assets			
Cash	13,653,974	17,656,630	14,180,256
Cash held in margin accounts (note 17)	-	31,043	607,929
Restricted cash (note 4)	2,418,264	2,708,217	3,707,130
Accounts receivable (note 5)	8,320,931	6,763,620	10,534,594
Inventory (note 6)	5,107,714	5,575,966	4,088,165
Prepaid expenses and deposits	923,480	1,524,457	2,556,406
Income taxes recoverable	-	229,636	-
	30,424,363	34,489,569	35,674,480
Non-current assets			
Property, plant and equipment (note 7)	75,324,183	75,052,993	80,241,445
Intangible assets (note 8)	2,679,836	2,766,284	2,996,803
Deferred income tax assets (note 25)	2,312,000	2,346,000	2,149,000
	110,740,382	114,654,846	121,061,728

Approved by the Board of Directors

_______________________ Director _______________________ Director

The accompanying notes are an integral part of these financial statements.

(expressed in Canadian dollars)

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	3,997,591	4,380,326	3,555,221
Income taxes payable	305,659	-	540,517
Fair value of commodity derivative contracts (notes 14 and 15)	492	100,662	898,991
Fair value of interest rate swap contracts (notes 14 and 21)	371,881	944,838	1,436,240
Current portion of finance lease obligation (note 10)	738,210	619,905	539,670
Current portion of term debt (note 9)	3,822,000	3,822,000	5,150,000
Current portion of research and development fund liability (note 18)	280,000	280,000	-
Current portion of subordinated debentures and notes (note 11)	-	-	731,544
	9,515,833	10,147,731	12,852,183
Non-current liabilities			
Finance lease obligation (note 10)	1,828,268	2,566,478	3,186,383
Term debt (note 9)	4,299,100	16,393,645	29,336,112
Research and development fund liability (note 18)	1,509,601	1,661,464	1,821,261
Subordinate debentures (note 11)	1,107,000	1,107,000	1,107,000
Deferred income tax liabilities (note 25)	13,080,000	9,857,000	6,390,000
	31,339,802	41,733,318	54,692,939
Shareholders' Equity			
Capital stock (note 12)	42,348,078	47,788,960	52,966,860
Contributed surplus (note 23)	673,246	703,186	806,150
Retained earnings	36,379,256	24,429,382	12,595,779
	79,400,580	72,921,528	66,368,789
	110,740,382	114,654,846	121,061,728

Commitments (note 17)
Contingencies (note 24)

The accompanying notes are an integral part of these financial statements.

Integrated Grain Processors Co-operative Inc.

Consolidated Statements of Operations and Comprehensive Income

For the years ended September 30, 2012 and 2011

(expressed in Canadian dollars)

	2012 $	2011 $
Sales	130,760,600	124,689,093
Cost of goods sold (note 16)	108,903,919	101,631,470
Gross profit	21,856,681	23,057,623
Selling, general and administrative expenses (note 19)	3,417,134	4,038,473
Operating income	18,439,547	19,019,150
Finance income (loss)		
Interest expense (note 20)	(1,967,709)	(3,060,457)
Interest and other income	50,493	52,207
Gain on interest rate swap contracts (note 21)	572,957	491,402
Gain (loss) on foreign exchange	(252,359)	251,134
Amortization of deferred financing costs	(905,455)	(1,229,533)
	(2,502,073)	(3,495,247)
Income before provision for taxes	15,937,474	15,523,903
Current income tax expense	730,600	420,300
Deferred income tax expense	3,257,000	3,270,000
	3,987,600	3,690,300
Net income and comprehensive income for the year	11,949,874	11,833,603

The accompanying notes are an integral part of these financial statements.

Integrated Grain Processors Co-operative Inc.

Consolidated Statements of Changes in Shareholders' Equity

For the years ended September 30, 2012 and 2011

(expressed in Canadian dollars)

	Capital stock $	Contributed surplus $	Retained earnings $	Total $
Balance - October 1, 2010	52,966,860	806,150	12,595,779	66,368,789
Net income and comprehensive income for the year			11,833,603	11,833,603
Return of capital	(5,247,520)	-	-	(5,247,520)
Options exercised and settled	78,120	(102,964)	-	(24,844)
New share issuances	500	-	-	500
Share conversions	5,000	-	-	5,000
Share redemptions	(14,000)	-	-	(14,000)
Balance - September 30, 2011	47,788,960	703,186	24,429,382	72,921,528
Net income and comprehensive income for the year			11,949,874	11,949,874
Return of capital	(5,456,882)	-	-	(5,456,882)
Options exercised and settled	30,000	(29,940)	-	60
Share conversions	500	-	-	500
Share redemptions	(14,500)	-	-	(14,500)
Balance - September 30, 2012	42,348,078	673,246	36,379,256	79,400,580

The accompanying notes are an integral part of these financial statements.

Integrated Grain Processors Co-operative Inc.

Consolidated Statements of Cash Flows

For the years ended September 30, 2012 and 2011

(expressed in Canadian dollars)

	2012 $	2011 $
Cash provided by (used in)		
Operating activities		
Net income and comprehensive income for the year	11,949,874	11,833,603
Charges (credits) to income not involving cash		
Depreciation and amortization	4,607,269	7,764,457
Unrealized gain on commodity derivative contracts	(100,170)	(798,329)
Interest on research and development fund liability	128,137	120,203
Loss on disposal of property, plant and equipment	-	9,296
Gain on interest rate swap contracts	(572,957)	(491,402)
Deferred income taxes	3,257,000	3,270,000
	19,269,153	21,707,828
Net change in non-cash working capital balances (note 22)	(335,522)	3,370,074
	18,933,631	25,077,902
Financing activities		
Repayments from subordinated debentures and notes	-	(731,544)
Net proceeds and redemptions of share subscriptions	(14,000)	(8,500)
Return of capital	(5,456,882)	(5,247,520)
Settlement of stock options (note 23)	60	(24,844)
Payment of term debt (note 9)	(13,000,000)	(15,500,000)
Payment of finance lease obligation	(619,905)	(539,670)
Payment of research and development fund liability (note 18)	(280,000)	-
Repayment of capital grant (note 18)	-	(179,021)
Restricted cash	289,953	998,913
Cash held in margin accounts	31,043	576,886
	(19,049,731)	(20,655,300)
Investing activities		
Purchase of property, plant and equipment	(3,886,556)	(988,228)
Proceeds from disposal of property, plant and equipment	-	42,000
	(3,886,556)	(946,228)
Net (decrease) increase in cash	(4,002,656)	3,476,374
Cash - Beginning of year	17,656,630	14,180,256
Cash - End of year	13,653,974	17,656,630
Supplemental operating cash flow information		
Interest paid	1,340,282	2,391,159
Interest received	(38,427)	(24,851)
Income taxes paid	425,000	1,195,000

The accompanying notes are an integral part of these financial statements.

(expressed in Canadian dollars)

1 Nature of operations

Integrated Grain Processors Co-operative Inc. (the Co-operative) was incorporated on April 4, 2002 under the Ontario Co-operative Corporations Act.

The Co-operative produces and sells ethanol and distillers grains through its 150,000,000 litre fuel ethanol production facility in Southwestern Ontario, which was completed on October 5, 2008.

The registered office and principal place of business of the Co-operative is 89 Progress Drive, Aylmer, ON, N5H 2R9.

2 Summary of significant accounting policies

Statement of compliance

In 2010, the Canadian Institute of Chartered Accountants (CICA) Handbook was revised to incorporate International Financial Reporting Standards (IFRS) effective for years beginning on or after January 1, 2011. Accordingly, the Co-operative has commenced reporting on this basis in its financial statements. In these financial statements, the Canadian generally accepted accounting principles (GAAP) refers to GAAP before the adoption of IFRS.

These consolidated financial statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board (IASB). Subject to certain transition elections disclosed in note 3, the Co-operative has consistently applied the same accounting policies throughout all periods presented, as if these policies had always been in effect. Note 3 discusses the impact of the transition to IFRS on the Co-operative's reported equity as at October 1, 2010 and September 30, 2011 and comprehensive income for the year ended September 30, 2011, including the nature and effect of significant changes in accounting policies from those used in the Co-operative's financial statements for the year ended September 30, 2011 prepared under GAAP.

Basis of measurement

The financial statements have been prepared using the historical cost approach on a going concern basis. They have been prepared in accordance with the accounting policies laid out below.

Principles of consolidation

The consolidated financial statements include the financial statements of the Co-operative and its wholly-owned subsidiary, IGPC Ethanol Inc. (the subsidiary). Intercompany balances and transactions have been eliminated on consolidation.

(expressed in Canadian dollars)

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the year reported. Actual results could differ from those estimates.

Critical accounting estimates

The useful lives and amortization of depreciable assets, which include primarily property, plant and equipment and intangible assets, are subject to significant estimate and have a significant risk of causing a material adjustment to the carrying amounts of depreciable assets. See detailed disclosure of property, plant and equipment and intangible asset useful lives noted below. A decrease of the average useful lives of depreciable assets by 1 year, would increase depreciation and amortization by $63,099 (2011 - $544,089). Management has not identified any other critical accounting estimates.

Presentation of revenue: gross versus net

When deciding the most appropriate basis for presenting revenue or costs of revenue, both the legal form and substance of the agreement between the Co-operative and its business partners are reviewed to determine each party's respective role in the transaction.

Where the Co-operative's role in a transaction is that of principal, revenue is recognized on a gross basis. This requires revenue to comprise the gross value of the transaction billed to the customer, after trade discounts, with any related expenditure charged as an operating cost.

Where the Co-operative's role in a transaction is that of an agent, revenue is recognized on a net basis with revenue representing the margin earned.

Revenue recognition

The Co-operative recognizes revenue on the sale of ethanol and distillers grains at the time of shipment.

Government assistance

The Co-operative estimates the timing and amount of assistance it will receive from government funding programs. Such estimates are based on past experience of receiving similar funding in the past.

Government grants are recognized when there is reasonable assurance that the Co-operative has complied with the conditions of the grant. Such grants are accounted for as a reduction of the related expense or asset, or as income, on a systematic basis over the periods in which the Co-operative recognizes as expenses the related costs for which the grants are intended to compensate as appropriate. Annual assessments are performed as to the likelihood of government grants becoming repayable.

(expressed in Canadian dollars)

Inventories

Inventories of finished products, feedstock, process chemicals and supplies are valued at the lower of net realizable value and average cost. Work in process consists of cost of material and direct labour and is valued at the lower of net realizable value and average cost.

Property, plant and equipment

Property, plant and equipment are stated at cost. Amortization is provided for using the straight-line method based on the estimated useful lives of the asset. The estimated useful lives are as follows:

Land	Indefinite
Buildings and site pipelines	20 to 35 years
Furniture and fixtures	10 years
Equipment	3 to 10 years
Process equipment	10 to 35 years

The Co-operative reviews the estimated useful lives of property, plant and equipment at the end of each annual reporting period.

Amortization of assets subject to a finance lease is calculated on a straight-line basis over the term of the lease.

In the year of acquisition, amortization is provided for on a pro-rated period for the number of days the asset is capable of operating in the manner intended by management. Amortization methods and residual values are reviewed annually for changes in circumstances that would result in changes in these estimates. A change in estimate is accounted for prospectively in the year the change occurred.

The assets are grouped by significant component and amortized over the period of that specific component. Annually long term assets are assessed for impairment by comparing the recoverable amount to the asset's carrying value.

Grants under government capital assistance programs are deducted from the cost of the assets to which the grant relates.

Intangible assets

Intangible assets relate to a license which grants the Co-operative the right to use the proprietary design and processes to produce ethanol and the control components of the plant technology. The license is being amortized over the estimated useful life of the significant portion of process equipment of 35 years.

(expressed in Canadian dollars)

Impairment of non-financial assets

At the end of each reporting period, the Co-operative reviews the carrying amounts of its non-financial assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any).

Recoverable amount is the higher of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to its recoverable amount. An impairment loss is recognized immediately in profit or loss.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset in prior years. A reversal of an impairment loss is recognized immediately in profit or loss.

Provisions

Provisions are recognized when the Co-operative has a present obligation, based on a legal or constructive requirement, resulting from a past event that is probable will result in an outflow of assets from the Co-operative and a reliable estimate of the amount can be made.

Leases

Assets held under finance leases are initially recognized as assets of the Co-operative at their fair value at the inception of the lease or, if lower, at the present value of the minimum lease payments. The corresponding liability to the lessor is included in the statement of financial position as a finance lease obligation.

Lease payments are apportioned between finance expenses and reduction of the lease obligation so as to achieve a constant rate of interest on the remaining balance of the liability. Finance expenses are recognized immediately in profit or loss, unless they are directly attributable to qualifying assets, in which case they are capitalised in accordance with the Co-operative's general policy on borrowing costs. Contingent rentals are recognized as expenses in the periods in which they are incurred.

Operating lease payments are recognized as an expense on a straight-line basis over the lease term, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognized as an expense in the period in which they are incurred.

(expressed in Canadian dollars)

Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale.

All other borrowing costs are recognized in profit or loss in the period in which they are incurred.

Financial instruments

Financial assets and financial liabilities are initially measured at fair value. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at fair value through profit or loss) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at fair value through profit or loss are recognized immediately in profit or loss. Financial assets are classified into the following specified categories: financial assets 'at fair value through profit or loss' (FVTPL), 'held-to-maturity' investments, 'available-for-sale' (AFS) financial assets and 'loans and receivables'. Financial liabilities are either classified as FVTPL or other liabilities.

- Financial assets at FVTPL are stated at fair value, with any gains or losses arising on remeasurement recognized in profit or loss.
- Available-for-sale financial assets are measured at their fair value and changes in fair value are included in other comprehensive income until the asset is removed from the statement of financial position.
- Loans and receivables are measured at cost or amortized cost using the effective interest rate method.
- Other financial liabilities are measured at cost or amortized cost using the effective interest rate method.
- Derivative instruments, including embedded derivatives, are measured at their fair value at the date the contract was entered into with changes in fair value recorded at the end of each reporting period and recognized in profit or loss for the year unless the instrument is a cash flow hedge and hedge accounting applies in which case changes in fair value are recognized in other comprehensive income.

(expressed in Canadian dollars)

The following is a summary of the classification of assets and liabilities of the Co-operative:

Financial Instrument	Classification
Cash	Loans and receivables
Restricted cash	Loans and receivables
Accounts receivable	Loans and receivables
Fair value of commodity derivative contracts	FVTPL
Accounts payable and accrued liabilities	Other financial liabilities
Fair value of interest rate swap contracts	FVTPL
Term debt	Other financial liabilities
Finance lease obligation	Other financial liabilities
Subordinated debentures and notes	Other financial liabilities
Research and development fund liability	Other financial liabilities

Stock options

Options are measured at fair value using the guidance in IFRS 2, *Share Based Payment* (IFRS 2). Stock-based compensation costs, measured at the grant date based on the fair value of the options granted and recognized over the service period involved, are recorded as expenses on the statement of operations and comprehensive loss. The amounts are credited to contributed surplus. An estimate of forfeitures is included in the amounts calculated. The consideration paid upon exercise of the options and the originally recorded fair valuc of the options are added to share capital.

Interest rate swap contracts

Exposure to interest rates on debt is managed through the use of interest rate swap contracts. These swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Changes in the fair value of the interest rate swap contracts have been recorded in the statement of operations and comprehensive income.

Foreign currency transactions

Foreign currency transactions are translated into Canadian dollars using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at exchange rates of monetary assets and liabilities denominated in currencies other than the Canadian dollar are recognized in the statement of operations.

Income taxes

Taxation on the profit or loss for the year comprises of current and deferred income tax. Taxation is recognized in the statement of operations except to the extent that it relates to items recognized directly in equity, in which case the income tax is recognized in equity.

(expressed in Canadian dollars)

Current income tax is the expected income tax payable on the taxable income for the year using rates enacted or substantially enacted at the year end, and includes any adjustments to tax payable in respect of previous years.

Deferred income taxes are calculated using the liability method on temporary differences between the carrying amounts of assets and liabilities and their tax bases. Deferred income tax is not provided on the initial recognition of goodwill or on the initial recognition of an asset or liability unless the related transaction is a business combination or affects tax or accounting profit. Where an asset has no deductible or depreciable amount for income tax purposes, but has a deductible amount on sale or abandonment for capital gains purposes, the amount is included in the determination of temporary differences.

Deferred income tax assets and liabilities are calculated at tax rates that are expected to apply to their respective period of realization, provided they are enacted or substantially enacted by the end of the reporting period.

Deferred income tax assets are recognized to the extent that it is probable that they will be able to be utilized against future taxable income. Deferred income tax assets are reviewed at each balance sheet date and adjusted to the extent that it is no longer probable that the related tax benefit will be realized.

Deferred income tax assets and liabilities are offset when they relate to income taxes levied by the same taxation authority and the Co-operative has both the right and the intention to settle its current assets and liabilities on a net or simultaneous basis.

Any changes in deferred income tax assets or liabilities are recognized as part of tax expense or income in profit or loss, except where they relate to items that are recognized in other comprehensive income (loss) or directly in equity, in which case the related deferred income tax is also recognized in other comprehensive income (loss) or equity, respectively.

Future accounting changes

Consolidated Financial Statements, Joint Ventures and Disclosures
In May 2011, the IASB issued three standards: IFRS 10, *Consolidated Financial Statements*, IFRS 11, *Joint Arrangements*, IFRS 12, *Disclosure of Interests in Other Entities*, and amended two standards: IAS 27, *Separate Financial Statements*, and IAS 28, *Investments in Associates and Joint Ventures*. Each of the new and amended standards has an effective date for annual periods beginning on or after January 1, 2013, with earlier application permitted if all the respective standards are simultaneously applied. These standards are not expected to have an impact on the Co-operative.

Fair Value Measurements
In May 2011, the IASB issued IFRS 13, *Fair Value Measurements* (IFRS 13). IFRS 13 establishes a single source of fair value measurement guidance that was previously provided across standards and sets out fair value measurement disclosure requirements. The standard requires information made available to users to be able to properly assess the impacts of fair value measurements and the estimates and assumptions used in determining those fair values. IFRS 13 is effective for annual periods beginning on or after January 1, 2013. The Co-operative has not yet determined the impact of IFRS 13 on its financial statements.

(expressed in Canadian dollars)

Financial Statement Presentation
In June 2011, the IASB issued amendments to IAS 1 *Financial Statement Presentation*. These amendments improve how components of other comprehensive income are presented. The new requirements are effective for annual periods beginning on or after 1 July 2012. These standards are not expected to have an impact on the Co-operative.

Financial Instruments
IFRS 9, *Financial Instruments* (IFRS 9) was issued by the IASB on November 12, 2009 and will replace IAS 39, Financial Instruments: Recognition and Measurement. IFRS 9 removes certain financial instrument classifications used to determine the asset measurement and addresses the calculation of impairment on financial instrument using a single impairment method. IFRS 9 is effective for annual periods beginning on or after January 1, 2015. The Co-operative has not yet determined the impact of IFRS 9 on its financial statements.

3 Transition to IFRS

As mentioned in note 2, prior to September 30, 2012 the consolidated financial statements of the Co-operative were prepared in accordance with GAAP with this set of consolidated financial statements being the first prepared in accordance with IFRS. The date of adoption and corresponding opening consolidated statement of financial position is October 1, 2010, being the Co-operative's "transition date" to IFRS. The provisions in IFRS 1 allow for several elective exemptions as well as mandatory exceptions to retrospective application as required when applying new accounting policies. On transition, there were adjustments made for the following reasons:

- Application of the components approach where each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item is depreciated separately in addition to the application of the guidance requiring the use of residual values as opposed to the lesser of residual and salvage value required under GAAP.

- The Co-operative determined there was a resulting deferred tax impact on the above adjustments as the accounting cost base changed for the property, plant and equipment with no corresponding change in the tax base.

- Application of the presentation standards under IFRS requires the statements of operations to be presented either based upon function or nature of the expense, following only one presentation format whereas a mixed format was permitted under GAAP, resulting in reclassification of line items above gross profit into cost of goods sold and also line items below gross profit into selling, general and administrative expenses and finance income and loss.

The adjustments were recorded in opening retained earnings on October 1, 2010, the Co-operative's transition date, as a transitional adjustment. Depreciation expense and deferred income taxes were adjusted for the year ended September 30, 2011 for the differences identified above. There was no impact on the consolidated statement of cash flows other than the changes to income not involving cash of the adjusted depreciation expense and deferred income tax provision as opposed to the one previously recorded under GAAP.

(expressed in Canadian dollars)

First-time adoption exemptions applied

IFRS 1 *First-time Adoption of International Financial Reporting Standards* (IFRS 1) sets forth guidance for the initial adoption of IFRS. Under IFRS 1 the standards are applied retrospectively at the transitional statement of financial position date with all adjustments to assets and liabilities taken to retained earnings unless certain exemptions are applied from full retrospective application. The Co-operative has applied the following exemptions to its opening consolidated statement of financial position dated October 1, 2010:

Share-based payment transactions
IFRS 1 encourages, but does not require, first-time adopters to apply IFRS 2 *Share-based Payments* to equity instruments that were granted subsequent to November 7, 2002, and vested before October 1, 2010. The Co-operative has elected not to apply IFRS 2 to awards that were granted and vested prior to October 1, 2010, which have been accounted for in accordance with GAAP.

Reconciliations and presentation differences

IFRS employs a conceptual framework that is similar to GAAP. However, significant differences exist in certain matters of recognition, measurement and disclosure. While adoption of IFRS has not changed the Co-operative's actual cash flows, it has resulted in changes to the Co-operative's reported financial position and results of operations. In order to allow the users of the financial statements to better understand these changes, the following tables show the total effect of the transition on the Co-operative's GAAP consolidated statements of operations and comprehensive income and the consolidated statements of financial position and show reconciliations of the comprehensive income and the equity to IFRS, with the resulting differences explained.

Certain presentation differences between previous GAAP and IFRS have no impact on reported income or total equity. As can be seen in the following tables, some line items are described differently (renamed) under IFRS compared to GAAP, although the assets and liabilities included in these line items are unaffected.

The presentation in accordance with IFRS differs from the presentation in accordance with GAAP.

(expressed in Canadian dollars)

Reconciliation of consolidated statement of financial position

	September 30, 2011			October 1, 2010		
	GAAP $	Adjustments $	IFRS $	GAAP $	Adjustments $	IFRS $
Assets						
Current assets						
Cash	17,656,630		17,656,630	14,180,256	-	14,180,256
Cash held in margin accounts	31,043	-	31,043	607,929	-	607,929
Restricted cash	2,708,217	-	2,708,217	3,707,130	-	3,707,130
Accounts receivable	6,763,620	-	6,763,620	10,534,594	-	10,534,594
Inventory	5,575,966	-	5,575,966	4,088,165	-	4,088,165
Prepaid expenses and deposits	1,524,457	-	1,524,457	2,556,406	-	2,556,406
Income taxes recoverable	229,636	-	229,636		-	-
Future income taxes	1,511,000	(1,511,000)	-	628,000	(628,000)	-
	36,000,569	(1,511,000)	34,489,569	36,302,480	(628,000)	35,674,480
Non-current assets						
Property, plant and equipment	74,504,491	548,502	75,052,993	79,829,439	412,006	80,241,445
Intangible assets	2,766,284	-	2,766,284	2,996,803	-	2,996,803
Deferred income tax assets	835,000	1,511,000	2,346,000	1,521,000	628,000	2,149,000
	114,106,344	548,502	114,654,846	120,649,722	412,006	121,061,728

(expressed in Canadian dollars)

Reconciliation of consolidated statement of financial position....*continued*

	September 30, 2011			October 1, 2010		
	GAAP	Adjustments	IFRS	GAAP	Adjustments	IFRS
	$	$	$	$	$	$
Liabilities						
Current liabilities						
Accounts payable and accrued liabilities	4,380,326	-	4,380,326	3,555,221	-	3,555,221
Income taxes payable	-	-	-	540,517	-	540,517
Fair value of commodity derivative contracts	100,662	-	100,662	898,991	-	898,991
Fair value of interest rate swap contracts	944,838	-	944,838	1,436,240	-	1,436,240
Current portion of capital lease obligation	619,905	-	619,905	539,670	-	539,670
Current portion of term debt	3,822,000	-	3,822,000	5,150,000	-	5,150,000
Current portion of research and development fund liability	280,000	-	280,000	-	-	-
Current portion of subordinated debentures and notes	-	-	-	731,544	-	731,544
	10,147,731	-	10,147,731	12,852,183	-	12,852,183
Non-current liabilities						
Capital lease obligation	2,566,478	-	2,566,478	3,186,383	-	3,186,383
Term debt	16,393,645	-	16,393,645	29,336,112	-	29,336,112
Research and development fund liability	1,661,464	-	1,661,464	1,821,261	-	1,821,261
Deferred income tax liabilities	9,718,000	139,000	9,857,000	6,285,000	105,000	6,390,000
Subordinated debentures	1,107,000	-	1,107,000	1,107,000	-	1,107,000
	41,594,318	139,000	41,733,318	54,587,939	105,000	54,692,939
Shareholders' Equity						
Capital stock	47,788,960	-	47,788,960	52,966,860	-	52,966,860
Contributed surplus	703,186	-	703,186	806,150	-	806,150
Retained earnings	24,019,880	409,502	24,429,382	12,288,773	307,006	12,595,779
	72,512,026	409,502	72,921,528	66,061,783	307,006	66,368,789
	114,106,344	548,502	114,654,846	120,649,722	412,006	121,061,728

(expressed in Canadian dollars)

Reconciliation of consolidated statement of operations and comprehensive income for the year ended September 30, 2011.

	GAAP $	Adjustments $	IFRS $
Net sales	124,689,093	-	124,689,093
Cost of goods sold	122,812,566	(21,181,096)	101,631,470
Depreciation and amortization	6,594,380	(6,594,380)	-
Net (gain) loss on commodity derivative contracts	1,056,061	(1,056,061)	-
Operating grants	(28,695,041)	28,695,041	-
	101,767,966	(136,496)	101,631,470
Gross profit	22,921,127	136,496	23,057,623
Selling, general and administrative expenses	3,961,433	77,040	4,038,473
Amortization of deferred finance costs and depreciation	1,306,573	(1,306,573)	-
	5,268,006	(1,229,533)	4,038,473
Operating income	17,653,121	1,366,029	19,019,150
Finance income (loss)			
Interest expense	(3,060,457)	-	(3,060,457)
Interest and other income	52,207	-	52,207
Gain on interest rate swap	491,402	-	491,402
Gain (loss) on foreign exchange	251,134	-	251,134
Amortization of deferred finance costs	-	(1,229,533)	(1,229,533)
	(2,265,714)	(1,229,533)	(3,495,247)
Income before provision for income taxes	15,387,407	136,496	15,523,903
Current income tax expense	420,300	-	420,300
Deferred income tax expense	3,236,000	34,000	3,270,000
	3,656,300	34,000	3,690,300
Net income for the year	11,731,107	102,496	11,833,603

(expressed in Canadian dollars)

4 Restricted cash

	September 30, 2012 $	September 30, 2011 $	October 1 2010 $
Debt service reserve account	2,418,264	2,708,217	3,497,575
Post completion account	-	-	209,555
	2,418,264	2,708,217	3,707,130

Under the terms of the credit agreement, as construction funds were obtained, a portion was added to the debt service reserve account such that at substantial completion the sum of two principal instalments plus six months of interest is available in a separate account to service bank debt. In the event cash flow is insufficient to meet the quarterly requirement, these funds may be used but must be replenished.

5 Accounts receivable

	September 30, 2012 $	September 30, 2011 $	October 1 2010 $
Trade accounts receivable	4,866,437	2,742,211	2,058,381
Allowance for doubtful accounts	-	-	-
Operating grants receivable (note 18)	3,454,394	4,016,990	8,403,816
Other receivables	100	4,419	72,397
	8,320,931	6,763,620	10,534,594

All of the Co-operative's trade accounts receivable balances were aged less than 30 days as at the year end dates.

6 Inventory

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Fuel grade ethanol	448,879	1,903,821	925,550
Work in process	1,260,717	1,076,700	1,143,096
Feedstock, process chemicals and supplies	3,398,118	2,595,445	2,019,519
	5,107,714	5,575,966	4,088,165

(expressed in Canadian dollars)

7 Property, plant and equipment

Cost	Land	Buildings	Site pipelines	Furniture and fixtures	Equipment	Process equipment	Gas pipeline under finance lease (note 10)	Construction in progress	Total
Balance - October 1, 2010	2,923,721	13,761,022	2,287,513	97,452	698,933	64,457,656	8,472,554	-	92,698,851
Additions	-	664,609	-	18,000	139,515	166,104	-	-	988,228
Repayment of capital grants	-	-	-	-	-	179,021	-	-	179,021
Disposals	-	-	-	-	(114,950)	-	-	-	(114,950)
Balance - September 30, 2011	2,923,721	14,425,631	2,287,513	115,452	723,498	64,802,781	8,472,554	-	93,751,150
Additions		10,063	-	9,740	80,455	143,875	-	3,642,423	3,886,556
Balance - September 30, 2012	2,923,721	14,435,694	2,287,513	125,192	803,953	64,946,656	8,472,554	3,642,423	97,637,706

Accumulated depreciation and impairment	Land	Buildings	Site pipelines	Furniture and fixtures	Equipment	Process equipment	Gas pipeline under finance lease (note 10)	Construction in progress	Total
Balance - October 1, 2010	-	1,298,589	228,752	14,954	115,105	8,379,276	2,420,730	-	12,457,406
Depreciation expense	-	666,577	114,376	9,693	100,965	4,138,775	1,210,365	-	6,240,751
Balance - September 30, 2011	-	1,965,166	343,128	24,647	216,070	12,518,051	3,631,095	-	18,698,157
Depreciation expense	-	368,982	55,551	10,768	89,154	1,880,546	1,210,365	-	3,615,366
Balance - September 30, 2012	-	2,334,148	398,679	35,415	305,224	14,398,597	4,841,460	-	22,313,523

(expressed in Canadian dollars)

The following is a reconciliation of the net book value for property, plant and equipment:

	Cost $	Accumulated depreciation $	Net book value $
Balance - October 1, 2010	92,698,851	12,457,406	80,241,445
Additions	988,228	-	988,228
Repayments of capital grants	179,021	-	179,021
Disposals	(114,950)	-	(114,950)
Depreciation expense	-	6,240,751	(6,240,751)
Balance - September 30, 2011	93,751,150	18,698,157	75,052,993
Additions	3,886,556	-	3,886,556
Depreciation expense	-	3,615,366	(3,615,366)
Balance - September 30, 2012	97,637,706	22,313,523	75,324,183

The maturing ethanol industry, in addition to the details provided by the Co-operative's rigorous maintenance program, presented management with supportable information justifying a change in estimated useful life. The estimated useful life was increased beyond that of a 1st generation dry mill ethanol manufacturing facility, conservatively used previously, to a longer period indicative of the construction materials utilized as well as the results of the maintenance and inspection over the past 4 years of operation. Consequently, the Co-operative prospectively revised the useful lives of property, plant and equipment effective October 1, 2011, which affected the useful lives of a number of assets, primarily buildings and process equipment. The revision results in the following change in the original trend of depreciation:

	$
2012	(2,775,049)
2013	(2,704,101)
2014	(2,658,328)
2015	(2,618,590)
After 2015	10,756,068

(expressed in Canadian dollars)

8 Intangible assets

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Cost	3,227,324	3,227,324	3,227,324
Accumulated amortization	(547,488)	(461,040)	(230,521)
Net book value	2,679,836	2,766,284	2,996,803

The following is a reconciliation of the net book value for the intangible asset:

	$
Balance - October 1, 2010	2,996,803
Amortization	(230,519)
Balance - September 30, 2011	2,766,284
Amortization	(86,448)
Balance - September 30, 2012	2,679,836

During the current year, the Co-operative reviewed and revised the useful life of the intangible asset resulting in the following change in the original trend of amortization:

	$
2012	(144,072)
2013	(144,072)
2014	(144,072)
2015	(144,072)
After 2015	576,288

9 Term debt

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Term debt	8,500,000	21,500,000	37,000,000
Less: Current portion	(3,822,000)	(3,822,000)	(5,150,000)
Less: Deferred financing costs	(378,900)	(1,284,355)	(2,513,888)
	4,299,100	16,393,645	29,336,112

(expressed in Canadian dollars)

The Co-operative entered into a credit agreement on June 15, 2007 with a lead bank as Agent for certain lenders to initially make the following credit facilities available:

a) A seven year non-revolving term loan facility for $63,700,000 to be used for construction of the plant with principal payments of $3,822,000 commencing in 2009, due June 27, 2014.

b) A seven year revolving term facility for working capital purposes not to exceed lesser of $7,000,000 or the borrowing base. Borrowing base uses as collateral 85% of eligible receivables and inventory. Subsequently to year end, the amount has been reduced to $6,000,000.

In 2009, the Co-operative had drawn the full amount allowed against the seven year non-revolving term loan facility. The revolving facility became available after substantial completion of the ethanol plant as defined under the credit agreement.

Deferred financing costs have been allocated to the term loan, revolving term facility and bridge facility. At year-end the unamortized balances allocated to these elements of the credit agreement are $185,300 (September 30, 2011 - $897,155; October 1, 2010 - $1,933,088), $193,600 (September 30, 2011 - $387,200; October 1, 2010 - $580,800) and $Nil (September 30, 2011 - $Nil; October 1, 2010 - $Nil) respectively.

As at September 30, 2012, the Co-operative had $2,754,481 (September 30, 2011 - $2,754,481; October 1 2010 - $2,754,481) of letters of credit drawn against the seven year revolving term facility.

During construction, interest was based on the variable banker's acceptance rate and a stamping fee of 3.75%. After substantial completion, the debt became a term debt with interest at the variable banker's acceptance rate and a stamping fee of 3.25% which was increased to 3.75% after negotiating the amendment to the credit agreement. The aggregate amount of minimum principal payments required in each of the next two years under debt facilities are:

	$
2013	3,822,000
2014	4,678,000
	8,500,000

Debt repayments made on each repayment date have been the greater: of 70% of excess cash flows; and the difference between the outstanding amount and the target outstanding debt to a maximum of 100% of the excess cash flows. The target outstanding debt is reduced by $2,895,455 per quarter. If there are no excess cash flows, the Co-operative is required to pay 1.5% of the initial debt outstanding for a total of $955,500 per quarter, which has been disclosed in the principal payments required above and adjusted for the target outstanding debt amount. As at September 30, 2012, the target debt outstanding was $20,268,175 (September 30, 2011 -$31,850,000; October 1, 2010 - $43,431,818). A voluntary prepayment feature allows the Co-operative to prepay a minimum of $500,000 with adequate notice to the Agent.

(expressed in Canadian dollars)

Since the inception of the seven year revolving term facility, the Co-operative has made the following principal payments:

	$
Term debt at inception	63,700,000
Principal payments in 2009	(9,728,812)
Principal payments in 2010	(16,971,188)
Principal payments in 2011	(15,500,000)
Principal payments in 2012	(13,000,000)
	8,500,000

Under the credit agreement, the Co-operative has provided security to the lenders, the key elements of which are as follows:

a) a fixed and floating charge debenture in the amount of $150,000,000;

b) a general security agreement covering all assets of the Co-operative;

c) an assignment of insurance; and

d) a limited recourse guarantee and a securities pledge agreement.

10 Finance lease obligation

As part of the construction of the ethanol plant, it was necessary for the local natural gas distributor to construct a 29km pipeline from a Union Gas trunk pipeline to the town of Aylmer. The costs of the pipeline are fully borne by the Co-operative, through 'aid-to-construct' payments, plus certain fixed gas delivery charges over a 7 year contract period. While the Co-operative has no ownership interest in the pipeline, accounting standards require that in such instances where the value of the asset is fully recovered by the supplier and the customer has exclusive, or virtually exclusive, use of the asset, the arrangement is accounted for as a lease.

(expressed in Canadian dollars)

Accordingly, the Co-operative has recorded the capital cost of the pipeline as a finance lease, and the discounted value of certain fixed gas delivery charges over the next 4 years as a finance lease obligation, with notional interest of 15%. The details of the finance lease obligation are as follows:

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Gross finance lease liabilities - minimum lease payments:			
No later than 1 year	1,066,248	1,066,248	1,066,248
Later than 1 year and no later than 5 years	2,132,496	3,198,744	4,264,992
	3,198,744	4,264,992	5,331,240
Future interest charges on finance leases	(632,266)	(1,078,609)	(1,605,187)
Present value of finance lease liabilities	2,566,478	3,186,383	3,726,053
The present value of finance lease liabilities is repayable as follows:			
No later than 1 year	738,210	619,905	539,670
Later than 1 year and no later than 5 years	1,828,268	2,566,478	3,186,383
	2,566,478	3,186,383	3,726,053

In addition to the foregoing, the Co-operative is obligated to provide a letter of credit to the natural gas distributor to ensure performance under the agreement. At year end, a letter of credit in the amount of $5,214,173 (September 30, 2011 - $5,214,173; October 1, 2010 - $5,214,173) was issued in their favour.

The final cost of the pipeline is currently under review by the Ontario Energy Board. Should the final costs differ from costs determined for purposes of calculating the finance lease obligation, the obligation will be adjusted accordingly.

(expressed in Canadian dollars)

11 Subordinated debentures and notes

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Class A debentures maturing on December 31, 2013 and bearing interest at 8.5% per annum	1,070,000	1,070,000	1,070,000
Class B debentures maturing on December 31, 2013 and bearing interest at 7.5% per annum	37,000	37,000	37,000
Promissory notes maturing on December 31, 2010 and bearing interest at 8.0% per annum	-	-	731,544
	1,107,000	1,107,000	1,838,544
Less: Current portion	-	-	731,544
	1,107,000	1,107,000	1,107,000

The redemption of these subordinate debentures at maturity and the payment of interest thereon are subject to the prior consent of the lenders.

(expressed in Canadian dollars)

12 Capital stock

Authorized

100,000 membership shares, voting, with a par value of $100 each.

20,000,000 Class E preference shares, non-voting, redeemable at the discretion of the Board, with a par value of $5 each.

The Class E preference shares are redeemable at their par value, plus a premium, if any, equivalent to a pro rata share of retained earnings of the Co-operative, calculated at the end of the immediately preceding fiscal year subject to certain conditions, plus a pro rata share of such premiums as may have been paid upon the purchase of any Class E preference shares. The preference shares do not carry a retraction right.

Each of the Class E preference shares is entitled to non-cumulative preferential dividends to be declared at the discretion of the Board.

	Membership		Class E		Total
	#	$	#	$	$
Balance - October 1, 2010	4,120	412,000	10,831,931	52,554,860	52,966,860
New share issuances	5	500	-	-	500
Exercised stock options	-	-	15,624	78,120	78,120
Share conversions	-	-	1,000	5,000	5,000
Share redemptions	(140)	(14,000)	-	-	(14,000)
Return of capital	-	-	-	(5,247,520)	(5,247,520)
Balance - September 30, 2011	3,985	398,500	10,848,555	47,390,460	47,788,960
Exercised stock options	-	-	6,000	30,000	30,000
Share conversions	-	-	100	500	500
Share redemptions	(145)	(14,500)	-	-	(14,500)
Return of capital	-	-	-	(5,456,882)	(5,456,882)
Balance - September 30, 2012	3,840	384,000	10,854,655	41,964,078	42,348,078

(expressed in Canadian dollars)

13 Capital disclosures

The Co-operative has two primary capital management objectives. The first of which is to raise and maintain a capital base to finance the construction and operation of the ethanol manufacturing facility. In compliance with the credit agreement, membership and preference shares and subordinate debentures (securities) have been issued. These securities are governed by the Co-operative Corporations Act. Annually, an Offering Statement is filed with the Financial Services Corporation of Ontario (the Superintendent).

The second primary capital management objective is to safeguard the Co-operative's ability to continue as a going concern so that it can provide returns to its shareholders and benefits for other stakeholders. In this context, management considers capital to be its consolidated net worth as defined in the credit agreement as containing shareholders' equity and capital grants. The Co-operative has no regulatory requirements with respect to capital; however, the agent for the syndicate of the term debt has imposed certain covenants in connection with the term debt and credit facilities. As at September 30, 2012, the Co-operative was in compliance with these covenants.

14 Financial instruments

Fair value

The fair value of financial instruments recorded as current, including cash, cash held in margin accounts, restricted cash, accounts receivable, and accounts payable and accrued liabilities are determined to approximate their recorded value due to their short term maturity.

Commodity derivative contracts and the interest rate swap contracts are carried at fair value.

The research and development fund liability has been recorded at fair value at the time of recognition and is carried at amortized cost (note 18).

Management has determined that the carrying value of its term debt, finance lease obligations and subordinated debentures and notes approximates fair value.

Credit risk

Credit risk is the risk of financial loss because a counter party to a financial instrument fails to discharge its contractual obligations. The Co-operative's exposure to credit risk relates to its cash, cash held in margin accounts, restricted cash and accounts receivable. Due to the exclusive marketing arrangements for ethanol and distillers grains, all of the trade accounts receivables are with two customers.

(expressed in Canadian dollars)

Liquidity risk

The Co-operative's approach to managing liquidity risk is to ensure that it will have sufficient liquidity to meet financial obligations when due through periodic monitoring of working capital balances. All of the Co-operative's current financial liabilities have contractual maturities that range between 30 and 90 days and are subject to normal trade terms excluding finance lease obligations (note 10), term debt (note 9), subordinated debentures and notes (note 11) and the research and development fund liability (note 18).

Interest rate risk

Interest rate risk is the risk that the value of a financial instrument might be adversely affected by a change in the interest rates. Changes in market interest rates may have an effect on the cash flows associated with some financial assets and liabilities, known as cash flow risk, and on the fair value of other financial assets or liabilities, known as price risk. The Co-operative is exposed to fluctuations in interest rates on its cash, restricted cash, and notes payable from parent and term debt. A portion of this risk due to variable interest rates has been addressed by the use of interest rate swap contracts (note 21).

The following table provides an analysis of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable.

- Level 1 fair value measurements are those derived from quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

September 30, 2012	Level 1 $	Level 2 $	Level 3 $	Total $
Fair value of commodity derivative contracts	-	492	-	492
Fair value of interest rate swap contracts	-	371,881	-	371,881
	-	372,373	-	372,373

(expressed in Canadian dollars)

September 30, 2011	Level 1 $	Level 2 $	Level 3 $	Total $
Fair value of commodity derivative contracts	-	100,662	-	100,662
Fair value of interest rate swap contracts	-	944,838	-	944,838
	-	1,045,500	-	1,045,500

October 1, 2010	Level 1 $	Level 2 $	Level 3 $	Total $
Fair value of commodity derivative contracts	-	898,991	-	898,991
Fair value of interest rate swap contracts	-	1,436,240	-	1,436,240
	-	2,335,231	-	2,335,231

There were no transfers between Level 1 and 2 in the year.

15 Commodity derivative contracts

The Co-operative is exposed to the impact of market fluctuations associated with commodity prices and uses derivative financial instruments as part of an overall strategy to manage market risk, assuming it has sufficient liquidity to manage such a strategy. The Co-operative uses cash, futures, swaps, costless collars and option contracts to mitigate against the risk of changes to the commodity prices of corn, natural gas and ethanol. The Co-operative will not enter into these derivative financial instruments for trading or speculative purposes, nor will it designate these contracts as cash flow or fair value hedges for accounting. These financial instruments are accounted for using thc mark-to-market method, with any changes in fair value immediately recognized in operations.

(expressed in Canadian dollars)

At year end, the Co-operative had the following derivative contracts outstanding:

September 30, 2012

	Average cost/price in USD	Expiry
Corn	$8.00 - $8.07 /bushel	December 2012 - March 2013

September 30, 2011

	Average cost/price in USD	Expiry
Natural gas	$4.25 - $5.00 /MMBtu	November 2011 - December 2011

October 1, 2010

	Average cost/price in USD	Expiry
Corn	$4.02 - $5.22 / bushel	December 2010 – March 2011
Ethanol	$1.62 / US gallon	October 2010 – April 2011
Natural gas	$4.50 - 6.00 / MMBtu	November 2010 – March 2011
RBOB*	$1.945 / US gallon	October 2010

The net market value of these open positions is an unrealized loss of $492 (September 30, 2011 - $100,662; October 1, 2010 - $898,991)

(*RBOB - reformulated gasoline blendstock for oxygenate blending)

16 Cost of goods sold

	2012 $	2011 $
Feedstock	111,363,665	101,907,548
Chemicals, enzymes, yeast and denaturant	6,279,664	5,795,448
Natural gas, electricity and water	9,071,907	8,749,724
Labour	3,323,925	3,501,061
Maintenance	1,782,404	1,467,673
Other production costs	495,899	477,787
Insurance	536,918	638,429
Property taxes	268,125	274,896
Depreciation and amortization	3,625,131	6,457,884
Net (gain) loss on commodity derivative contracts	(378,217)	1,056,061
Operating grants (note 18)	(27,465,502)	(28,695,041)
	108,903,919	101,631,470

(expressed in Canadian dollars)

17 Commitments

Corn supply agreement

The Co-operative has entered into an exclusive agreement for the supply of corn for production of ethanol for an initial term of five years from October 1, 2008, and it is expected that 400,000 metric tonnes are to be supplied each year. The Co-operative is also required under the agreement to provide adequate assurance for the corn supplier's mark-to-market exposure over a pre-determined threshold. At year end, the Co-operative had deposited $Nil (September 30, 2011 - $Nil; October 1, 2010 - $437,529) with the corn supplier with respect to this commitment, and this amount is recorded in cash held in margin accounts in the statement of financial position.

Risk management agreement

The Co-operative has entered into an agreement with a risk management services provider to implement an integrated price risk management program for an initial term of one year from June 22, 2007 and is automatically renewed each year for an additional one year term.

Ethanol marketing agreement

The Co-operative has entered into an exclusive agreement with an ethanol marketer for the marketing of all of the ethanol production for an initial term of one year from the first day of production, which was October 15, 2008, and the agreement has been renewed for a second additional two year term. The ethanol marketing company has agreed to take and pay for 100% of the output.

Distillers grain purchaser agreement

The Co-operative has entered into an exclusive agreement with a marketer to market the following by-products of ethanol production: dry grains with solubles, wet grains with solubles, and wet modified grains with solubles for an initial term of five years from the first day of production, which was October 15, 2008.

18 Government grants

Ontario Ministry of Agriculture, Food and Rural Affairs (OMAFRA)

The Co-operative has been awarded two grants from OMAFRA:

a) In March 2009, the Co-operative received a capital grant of $14,000,000 after completion of the project and achieving nameplate capacity by establishing the capability of producing 145 million litres of ethanol in a calendar year. As a condition precedent to receiving the grant, the Co-operative is committed to contribute $2,800,000 over ten years to a future industry related Research and Development Fund, as administered by the Agricultural Research Institute of Ontario. The first payment was made on April 1, 2012, three years after the full grant was received. An amount of $1,653,921, representing the present value of these payments discounted at 6.60%, was recorded as a

(expressed in Canadian dollars)

research and development fund liability, thus reducing the amount of capital grant recognized for the purpose of recording the net cost of property, plant and equipment. At year end, the balance of this obligation was $1,789,601 (September 30, 2011 - $1,941,464; October 1, 2010 - $1,821,261).

b) An operating grant was activated when the plant began operation in October 2008. Funding is based on the actual volume of denatured ethanol produced in a month times the rate of payment for that month (not to exceed $0.11 per litre) subject to an annual maximum of 145 million litres. During the current and prior year, the Co-operative reached this maximum and earned $14,989,921 (2011 - $14,918,113) in operating grants earned at $0.1029 per litre (2011 - $0.1028 per litre), of which $1,374,816 (September 30, 2011 - $1,818,598; October 1, 2010 - $1,868,872) has been accrued as an amount receivable. The agreement is set to expire December 31, 2016.

If the profitability of the Co-operative reaches or exceeds the threshold of 17.50% as calculated by the internal rate of return on a cash flow basis, the grant is reduced by 40%. This reduction increases incrementally up to 100% if profitability remains above 17.50%. As at September 30, 2012 and September 30, 2011, the Co-operative's internal rate of return was below the threshold of 17.50%.

Ethanol Expansion Program contribution

This capital grant, managed by Natural Resources Canada (NRCan), has reimbursed $11,900,000 of construction costs for the ethanol facility.

For each of the calendar years from 2009 to 2016 inclusive or until the grants have been repaid in full, the Co-operative must repay an amount calculated as of December 31 of each year as follows:

(Average Gross Income per Litre minus $0.20 per litre) X (the total Fuel Ethanol Produced in the previous twelve (12) months) X (0.20).

If the average gross income per litre is $0.20 or less, the repayment will be zero. During the year, the Co-operative repaid $Nil (2011 - $179,021) of this capital grant.

ecoEnergy for Biofuels

The Co-operative qualified for an operating grant under the Federal Government's ecoEnergy for Biofuels program, managed by NRCan. The operating grant is payable quarterly, from 2008 to 2016. The maximum incentive rate payable declines from $0.10 per litre of ethanol sold in the first year to $0.04 per litre in the last. The maximum eligible sales volume is 162,000,000 litres per year. During the current and prior years, the Co-operative reached the maximum eligible sales volume and earned $12,475,581 (2011 - $13,776,928) in operating grants earned at $0.077 per litre (2011 - $0.0849 per litre) of which $ 2,079,578 (September 30, 2011 - $2,198,392; October 1, 2010 - $6,534,944) has been accrued as an amount receivable.

(expressed in Canadian dollars)

19 Selling, general and administrative expenses

	2012 $	2011 $
Short-term compensation expense	1,281,192	1,257,690
Bank fees and related charges	498,557	604,898
Consulting and professional fees	558,960	877,110
Memberships	254,175	253,889
Office and administration	369,273	448,929
Risk management	69,647	82,833
Travel	63,705	63,197
Co-operative administration	244,940	372,887
Depreciation	76,685	77,040
	3,417,134	4,038,473

20 Interest expense

	2012 $	2011 $
Term debt	785,247	1,577,257
Settlement interest on swap	514,072	729,012
Capital lease obligation	446,343	526,584
Interest on research and development fund liability	128,137	120,203
Subordinated debentures and notes	93,910	103,365
Other	-	4,036
	1,967,709	3,060,457

21 Interest rate swap contracts

Under the terms of the credit agreement, on August 30, 2007, the Co-operative entered into monthly interest rate swap contracts to match the construction drawdown and term debt repayment schedule. These swap agreements convert a portion of the variable-rate liability into a fixed-rate liability. At September 30, 2012, the unrealized loss on these interest rate swap agreements was $371,881 (September 30, 2011 - $944,838; October 1, 2010 - $1,436,240).

Terms of the agreement at September 30, 2012 are as follows:

Termination date:	June 1, 2014
Notional amount of principal (maximum):	September 30, 2012 - $10,134,091 September 30, 2011 - $15,925,000 October 1, 2010 - $21,175,909
Fixed paying rate:	4.91%

(expressed in Canadian dollars)

22 Net change in non-cash working capital balances

	2012 $	2011 $
(Increase) decrease in		
Accounts receivable	(1,557,311)	3,770,974
Inventory	468,252	(1,487,801)
Prepaid expenses and deposits	600,977	1,031,949
Income taxes recoverable	229,636	(229,636)
Increase (decrease) in		
Accounts payable and accrued liabilities	(382,735)	825,105
Income taxes payable	305,659	(540,517)
	(335,522)	3,370,074

23 Stock options

The Co-operative is authorized to grant certain directors options to purchase Class E preference shares of the Co-operative. The Co-operative, in a prior year, authorized $695,300 worth of Class E preference share options to certain directors for services provided prior to substantial completion of the ethanol plant which occurred on October 15, 2008.

These options vest when issued and under the Co-operative Corporations Act are exercisable at $5.00 per share until they expire on June 24, 2017. They will be deemed to have been automatically exercised immediately before any change in control of the Co-operative or before the sale of substantially all of its assets.

The Co-operative had also, in a prior year, authorized $124,500 worth of Class E preference share options and $500 worth of membership share options to a non-employee for services provided leading up to obtaining financing. These options were settled with a cash payment of $25,000 in the prior year and $100,000 in a prior year.

During the year, the Co-operative received $60 (2011 - $156) from the exercise of 6,000 (2011 - 15,624) options at $0.01 per Class E preference share. Additionally, contributed surplus was adjusted by $29,940 (2011 - $77,964) for stock-based compensation previously recorded on these exercised stock options.

	September 30, 2012		September 30, 2011		October 1, 2010	
	#	$	#	$	#	$
Total stock options - beginning of year	123,436	617,336	139,060	695,300	139,060	695,300
Options exercised during year	6,000	(29,940)	15,624	(77,964)	-	-
Total stock options - end of year	117,436	587,396	123,436	617,336	139,060	695,300

(expressed in Canadian dollars)

24 Contingencies

The Co-operative has been named as a defendant in a lawsuit arising from the construction of the gas pipeline. The outcome of this claim is not currently determinable, however management is of the view that no payments will be made, other than defense costs, as a result of the claim. Any settlement that should arise will be accounted for in the year that a liability is established.

25 Income tax

The income tax on the Co-operative's income before tax differs from the amount that would result using the theoretically applicable tax rate of the Co-operative as follows:

	2012		2011	
	$	%	$	%
Income before income tax	15,937,474		15,523,903	
Income tax calculated at applicable tax rate	4,044,625	25.3	4,172,825	26.9
Expenses not deductible for tax purposes	11,969	0.1	21,823	0.1
Effect on deferred tax expense from changes in tax rates	(118,624)	(0.7)	(445,969)	(2.8)
Other	49,630	0.3	(58,379)	(0.4)
	3,987,600	25.0	3,690,300	23.8

(expressed in Canadian dollars)

Deferred income taxes

Tax liabilities by types of temporary differences:

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Deferred income tax assets			
Unrealized gain on contracts	93,000	265,000	628,000
Investment tax credit carryforward	-	65,000	-
Research and development fund liability	447,000	485,000	455,000
Credit carryforward corporate minimum tax	1,338,000	1,136,000	716,000
Non-capital loss carryforward	434,000	395,000	350,000
Total deferred income tax assets	2,312,000	2,346,000	2,149,000
Deferred income tax liabilities			
Property, plant and equipment	12,638,000	9,224,000	5,561,000
Intangible assets	97,000	83,000	93,000
Gas pipeline	266,000	414,000	582,000
Deferred financing costs	79,000	136,000	154,000
Total deferred income tax liabilities	13,080,000	9,857,000	6,390,000

	September 30, 2012 $	September 30, 2011 $	October 1, 2010 $
Deferred income tax assets to be recovered within one year	1,431,000	1,466,000	628,000
Deferred income tax assets to be recovered after more than one year	881,000	880,000	1,521,000
	2,312,000	2,346,000	2,149,000
Deferred income tax liabilities to be recovered within one year	-	-	-
Deferred income tax liabilities to be recovered after more than one year	13,080,000	9,857,000	6,390,000
	13,080,000	9,857,000	6,390,000

(expressed in Canadian dollars)

The movements on the deferred income tax balances are as follows:

	Deferred income tax assets $	Deferred income tax liabilities $
Balance at October 1, 2010	2,149,000	6,390,000
Deferred income tax expense (recovery)	(197,000)	3,467,000
Balance at September 30, 2011	2,346,000	9,857,000
Deferred income tax expense	34,000	3,223,000
Balance at September 30, 2012	2,312,000	13,080,000

26 Compensation of key management personnel

The remuneration of directors and other members of key management personnel during the year was as follows:

	2012 $	2011 $
Short-term compensation expense	1,758,766	1,801,334

27 Approval of financial statements

The financial statements were approved by the Board of Directors on December 12, 2012.

pwc

March 15, 2013

AUDITOR'S CONSENT

We have read the offering statement of Integrated Grain Processors Co-operative Inc. ("Co-operative") dated March 1, 2013 relating to the issue and sale of Membership Shares and Class E Preference Shares of the Co-operative. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the above-mentioned offering statement of our report to the shareholders of the Co-operative on the consolidated balance sheets of the Co-operative as at September 30, 2012, September 30, 2011 and October 1, 2010, and the consolidated statements of operations and retained earnings and cash flows for the years ended September 30, 2012 and September 30, 2011. Our report on the consolidated financial statements is dated December 12, 2012.

PricewaterhouseCoopers LLP

Chartered Accountants, Licensed Public Accountants

Integrated Grain Processors Co-operative Inc

Consolidated Statements of Financial Position
(Unaudited)

As at	December 31, 2012	September 30, 2012
	$	$
Assets		
Current assets:		
Cash	13,394,145	13,653,974
Cash held in margin accounts	357,603	.
Restricted cash	2,442,489	2,418,264
Accounts receivable	11,947,188	8,320,931
Inventory	5,247,022	5,107,714
Prepaid expenses and deposits	1,775,382	923,480
Fair market value of commodity derivatives	163,967	-
	35,327,976	30,474,983
Non-current assets		
Investments	135,000	-
Property, plant and equipment	74,455,430	75,324,183
Intangible asset	2,658,224	2,679,836
Deferred income tax assets	1,964,000	2,312,000
	114,540,630	110,740,382
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable and accrued liabilities	4,135,217	3,997,591
Income taxes payable	1,192,103	305,659
Current portion of term debt	3,822,000	3,822,000
Current portion of subordinate debentures	1,107,000	.
Current portion of finance lease obligation	854,041	738,210
Current portion of research and development fund liability	280,000	280,000
Fair market value of commodity derivative contracts	-	492
Fair market value of interest rate swap	275,925	371,881
	11,666,286	9,615,833
Non-current liabilities		
Finance lease obligation	1,537,846	1,828,268
Subordinate debentures	*	1,107,000
Term debt	3,308,434	4,299,100
Research and development fund liability	1,541,439	1,509,601
Deferred income tax liabilities	12,962,000	13,080,000
Preference shares	.	'
	31,016,005	31,339,802
Shareholders' Equity		
Capital stock	42,304,478	42,348,078
Contributed Surplus	673,246	673,246
Retained earnings	40,546,901	36,379,256
	83,524,625	79,400,580
	114,540,630	110,740,382

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Integrated Grain Processors Co-operative Inc

Consolidated Statements of Operations and Comprehensive Income
(Unaudited)

	Quarter 1 ended December 31, 2012 $	Year to Date December 31, 2012 $	Year to Date December 31, 2011 $
Sales	33,876,400	33,876,400	34,932,221
Cost of goods sold	34,270,219	34,270,219	31,443,269
Depreciation and amortization	923,017	923,017	906,283
Net loss (gain) on commodity derivative contracts	(149,113)	(149,113)	136,536
Operating grants	(7,861,843)	(7,861,843)	(7,259,048)
	27,182,280	27,182,280	25,227,040
Gross profit	6,694,120	6,694,120	9,705,181
Selling, general and administrative expenses	1,013,000	1,013,000	693,912
Amortization and depreciation	14,001	14,001	19,171
	1,027,001	1,027,001	713,083
Operating income	5,667,119	5,667,119	8,992,098
Finance income (loss)			
Interest expense	(356,317)	(356,317)	(590,466)
Interest and other income	251,163	251,163	13,869
Gain on interest rate swap contracts	95,956	95,956	182,413
Gain (loss) on foreign exchange	20,912	20,912	(183,908)
Amortization of deferred finance costs	(109,334)	(109,334)	(270,356)
	(99,620)	(99,620)	(848,448)
Income before provision for taxes	5,567 499	5,567,499	8,143,650
Current income tax expense	1,467,854	1,467,854	373,318
Deferred income tax expense (recovery)	(68,000)	(68,000)	1,664,245
	1,399,854	1,399,854	2,037,564
Net income and comprehensive income for the period	4,167,645	4,167,645	6,106,086

Integrated Grain Processors Co-operative Inc

Consolidated Statements of Changes in Shareholders' Equity
(Unaudited)

	Capital Stock $	Contributed surplus $	Retained Earnings $	Total $
Balance - September 30, 2011	47,788,960	703,186	24,429,382	**72,921,528**
Net income and comprehensive income for the year	-	-	11,949,874	**11,949,874**
Return of Capital	(5,456,882)	-	-	**(5,456,882)**
Options exercised and settled	30,000	(29,940)	-	**60**
Share conversion	500	-	-	**500**
Share redemptions	(14,500)	-	-	**(14,500)**
Balance - September 30, 2012	42,348,078	673,246	36,379,256	**79,400,580**
Net income and comprehensive income for the year	-	-	4,167,645	**4,167,645**
Return of Capital	(42,100)	-	-	**(42,100)**
Share redemptions	(1,500)	-	-	**(1,500)**
Balance - December 31, 2012	42,304,478	673,246	40,546,901	**83,524,625**

Integrated Grain Processors Co-operative Inc

Consolidated Statements of Cash Flows
(Unaudited)

	Quarter 1 ended December 31, 2012 $	Year to Date December 31, 2012 $	Year to Date December 31, 2011 $
Cash provided by (used in)			
Operating activities			
Net income and comprehensive income for the period	4,167,645	4,167,645	6,108,066
Charges (credits) to income not affecting cash			
Depreciation and amortization	1,046,352	1,046,352	1,195,810
Unrealized gain on commodity derivative contracts	(164,459)	(164,459)	(698,690)
Gain on interest rate swap contracts	(95,956)	(95,956)	(182,413)
Interest on research and development fund liability	31,838	31,838	32,034
Deferred income taxes	230,000	230,000	1,664,245
	5,215,420	5,215,420	8,116,873
Change in non-cash working capital balances	(3,951,200)	(3,951,200)	(2,924,016)
	1,264,220	1,264,220	5,192,857
Financing activities:			
Shares issued and redeemed	(1,500)	(1,500)	-
Payment of term debt	(1,000,000)	(1,000,000)	(5,000,000)
Return of Capital	(42,100)	(42,100)	(60,187)
Payment of finance lease obligation	(174,591)	(174,591)	(146,795)
Payment of deferred finance costs	(100,000)	(100,000)	-
Restricted cash	(24,205)	(24,205)	(1,887)
	(1,342,396)	(1,342,396)	(5,208,869)
Investing activities			
Purchase of property and equipment	(46,653)	(46,653)	(70,820)
Other investments	(135,000)	(135,000)	-
	(181,653)	(181,653)	(70,820)
Net decrease in cash	(259,829)	(259,829)	(86,832)
Cash, beginning of period	13,653,974	13,653,974	17,656,630
Cash, end of period	13,394,145	13,394,145	17,569,798

Integrated Grain Processors Co-operative

September 30, 2012

Sales Reconciliation

Sales per Audited - Consolidated Statement of Operations and Comprehensive income

	2012	2011
Sales	130,760,600	124,689,093

Sales by Product

	2012	2011
Ethanol	108,821,228	105,813,256
DDG	17,375,238	16,015,439
WDG	4,441,858	2,683,681
CDS	122,276	176,717
	130,760,600	124,689,093
	-	-

THE GLOBE AND MAIL

February 22, 2013

Ottawa ending biofuels subsidy over unfulfilled industry promises

By Shawn McCarthy

The biodiesel industry has been unable to produce as much renewable fuel as had been promised, Natural Resources Minister Joe Oliver said in a letter

The Conservative government is formally shutting down its controversial biofuels subsidy program, saying companies producing biodiesel have failed to meet ambitious production targets.

In a letter sent Thursday, Natural Resources Minister Joe Oliver rejected calls from the industry to provide new money under Ottawa's ecoEnergy program to ethanol or biodiesel firms looking to build plants. Existing commitments, however, will be met until the program expires in 2017. A copy of the letter was obtained by The Globe and Mail.

"The government will not redesign or reopen the ecoEnergy for biofuels programs to new applicants," Mr. Oliver said. "During this time of fiscal restraint and challenging global fiscal realities, our government has committed to ensuring that we balance our budget."

Ottawa has already paid out $672-million to companies that have built plants to make grain-based ethanol and biodiesel, which has created 800 jobs and a new market for farmers. It expects to spend $1-billion on biofuels subsidies when the last payments are made in 2017, though the program was initially promoted as a $1.5-billion effort.

The government stopped taking applications under the program in 2010, but several companies have announced plans to build new biodiesel plants and the industry has been urging the government since then to continue the subsidy program. In November, 2011, U.S. agrifood giant Archer Daniels Midland announced plans to build a 265-million-litre-a-year biodiesel plant in Lloydminster, Alta., next to its canola crushing plant.

"Our members are ready to build new plants today," said Scott Thurlow, president of the Canadian Renewable Fuels Association. "They have shovel-ready projects which if the programs was reopened, they could absolutely make good on the Prime Minister's commitment to have 600 million litres of domestic biodiesel production in place."

Mr. Thurlow said the decision was "incredibly disappointing," and he questioned the timing of the announcement, given the escalating pressure on Ottawa to make more progress on combatting climate change.

In his letter, Mr. Oliver praised the ethanol industry, which is now producing virtually all the renewable fuel needed for Canada to meet its target of 5 per cent ethanol in the gasoline supply. But there are no ethanol producers with proposals for plants that would depend on the subsidy program.

In his letter to the industry, the minister noted the biodiesel industry has been unable to produce as much renewable fuel as had been promised. Critics have complained that biofuels from grain represent more of a subsidy to farmers than an environmental program, though Ottawa insists the growth of renewable fuel production has helped reduce greenhouse gases in the transportation sector.

But the minister added that the Canadian biodiesel industry "has not been able to produce and sell the large quantities of fuel that were forecasted." And Canadian refiners complained that the renewable diesel often did not meet their specifications and could not be easily blended with diesel.

As a result, much of the biodiesel produced in Canada has been exported, while refiners in some regions have been forced to import the renewable fuel to meet the 2-per-cent diesel target.

The ecoEnergy biofuels program came under fire last fall when The Globe and Mail revealed that one company, Great Lakes Biodiesel Inc., was in line for $65-million in subsidies for a plant it is building in St. Catharines, despite being investigated for improper shipments of American fuel to Europe. Great Lakes received a commitment for payments from Ottawa, but must actually produce biodiesel in order to collect.

What the industry wants

- Re-opening of the ecoEnergy Biofuels program. Cost: $190-million over five years.
- Direct unused ethanol money in the ecoEnergy fund to support next-generation biofuels made from agricultural and municipal waste. Provide incentive for those next-generation biofuel producers. Cost: $50-million.
- Preserve the $500-million NextGen Biofuels Fund which is used to subsidize construction of cellulosic ethanol and biodiesel–from-waste plants.

What Ottawa is doing

- Ending ecoEnergy Biofuels program to new applicants, but it will provide subsidies to ethanol and biodiesel producers under existing commitments until 2017 for total cost of $1-billion.
- Maintaining fuel regulations that require a 5-per-cent ethanol mix in gasoline and a 2-per-cent biodiesel component in the diesel supply, with exemptions to Atlantic Canada heating oil suppliers.
- Preserving the NextGen Biofuels fund, but it has made no commitment to provide incentive to producers .

With a report from Daniel Leblanc

The Globe and Mail, Inc.

IGPC

IGPC Ethanol Inc.

February 6th, 2013

Natural Resource Gas Limited
C/o Ayerswood Development
Anthony H. Graat, President
1299 Oxford Street East
London, ON
N5Y 4W5

Dear Mr. Graat,

Thank you for your letter of January 24th, 2013.

I find your concerns regarding IGPC's financial viability puzzling. To the best of my knowledge, IGPC has always promptly paid our bill and regardless, you have security on those payments.

We have also fully met our obligations under Pipeline Cost Recovery Agreement (PCRA) and once again you hold ample security on those obligations.

I would be happy to meet with you to discuss future plans of IGPC, and how NRG can support one of its largest customers. Prior to that however, I would ask that NRG honour its obligations as dictated by the PCRA agreement.

I look forward to your response.

Sincerely Yours,

per Jim Grey, CEO
IGPC Ethanol Inc.

89 Progress Drive, P.O. Box 205, Aylmer ON N5H 2R9 • Tel. 519.765.2575 • 866.211.0435 • Fax 519.765.2775

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

VIA COURIER

February 6, 2013

IGPC
89 Progress Drive
P.O. 205
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey,

Please find enclosed the Notice of Sale for an Ethanol facility in Collingwood, which I assume you are familiar with.

As per our previous request, please forward the requested information

Regards,

Natural Resource Gas Limited

Anthony H. Graat
President

WALL STREET JOURNAL

Ms. Banks sought to prevent with her gift and is a departure from the "Jeffersonian"-style campus initially envisioned at the property, known as Belward Farm.

The family sued in late 2011, alleging Johns Hopkins was violating the terms of the agreement with Ms. Banks. A Montgomery County circuit court judge dismissed that case in October, ruling Johns Hopkins was acting within the terms of the deed. Earlier this month, the family retained a corporate law firm, Sidley Austin LLP, to argue an appeal that is expected to be heard this spring.

"We're not asking for anything of them except to live up to the initial agreement," says

doesn't specify items such as density or how much can be leased commercially.

"The uses that we plan for the property are those that were expressly agreed to in the agreement and that we have intended from the beginning," says a Johns Hopkins spokesman.

The case spotlights the tricky world of donor intent, an area that is prone to fights over the initial objectives of a donor, sometimes decades later, between benefactors and their heirs and the institutions they believe have strayed away from the purpose.

Some institutions have given some money back after coming under pressure. In 2008, for example, Princeton University

gifts are often worded ambiguously. "A lot depends on how clearly and indisputably the donor specified his or her intentions," says Leslie Lenkowsky, a professor at Indiana University's Center on Philanthropy.

The Belward Farm land in Maryland is near other tracts of former farmland that attracted housing development thanks to its proximity to Washington. Ms. Banks and her family, however, resisted offers from numerous developers that wanted to build housing on the land, which was appraised for more than $50 million in the 1980s.

Ms. Banks didn't attend Johns Hopkins, but she believed the school would preserve as much open space as possible, Mr. New-

research school ... cluster of different researchers in a dense environment.

"You don't get your eureka moments sitting in the lab as much as you do talking to a colleague over coffee," says Alan Fish, Johns Hopkins's vice president for real estate.

The school hasn't specified how much of the space would be used by Johns Hopkins or leased to others. It also hasn't scheduled a groundbreaking yet.

Still, for Mr. Newell, the changing winds in the scientific research shouldn't give Johns Hopkins the ability to veer away from his aunt's wishes. "We could have sold it back then and been well off people," Mr. Newell says of the late 1980s.

120 days	0.33	0.33	0.38	0.33
150 days	0.38	0.38	0.38	0.33
180 days	0.38	0.38	0.53	0.38

Treasury
Treasury
Treasury

Other short-term rates

	Latest	Week ago	52-WEEK high	52-WEEK low
Call money	2.00	2.00	2.00	2.00
Commercial paper				
30 to 89 days	0.09			
90 to 119 days	0.12			

Eurodol
One mon
Two mon
Three mo
Four mont
Five mont
Six month

Notes on data:
U.S. prime rate is effective December 16, 2008. **Discount rate** is e[illegible] **rate** is the base rate on corporate loans posted by at least 70% of th[illegible] **rates** aren't directly comparable; lending practices vary widely by l[illegible] loans to depository institutions by the New York Federal Reserve B[illegible] reserves traded among commercial banks for overnight use in amou[illegible] **rate** is the charge on loans to brokers on stock-exchange collateral; [illegible] from the Federal Reserve and is presented with a one-day lag. **Libor**, [illegible] average of interbank offered rates for dollar deposits in the London [illegible] market; semi-annual swap rates and pay the floating 3-month Libor [illegible] Depository Trust & Clearing Corp.'s weighted average for overnight [illegible] traded is in billions of U.S. dollars. DTCC GCF **Repo Index futures** are [illegible]
Sources: Federal Reserve; Bureau of Labor Statistics; DTCC; ICAP plc; General Electric Capital Corp.; Tullett Prebon Information, Ltd.

DRAFT PER LARRY

>NOT SENT
DO NOT WANT OEB INVOLVED.
Business matter

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

January 29, 2013

IGPC
89 Progress Drive
P.O. 205
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey,

Further to NRG's recent correspondence, NRG has not received a response from IGPC regarding NRG's request for financial information.

NRG must take the steps necessary to protect its' rate payers from credit and other risks. NRG would prefer to resolve its' concerns about IGPC's credit risk without a formal proceeding with the OEB. However, if we do not receive a satisfactory response from IGPC, NRG will have no choice but to proceed before the OEB. NRG hopes this will not be necessary.

Regards,

Natural Resource Gas Limited

Anthony H. Graat
President

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

VIA COURIER

January 24, 2013

IGPC
89 Progress Drive
P.O. 205
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey,

Thank you for your letter of January 18, 2013.

I am currently out of town, but will be returning next week. As you well know, NRG has serious concerns as to IGPC's financial viability. Please call me to arrange a meeting with you to alleviate these concerns.

Regards,

Natural Resource Gas Limited

/per

Anthony H. Graat
President

IGPC

IGPC Ethanol Inc.

January 18th, 2013

Natural Resource Gas Limited
c/o Ayerswood Development
Anthony H. Graat, President
1299 Oxford Street East
London, ON
N5Y 4W5

Dear Mr. Graat,

Thank you for your letter of January 11th, 2013.

I would be available to meet with you to discuss any open topics. However, as a precursor to any meeting, I would insist that NRG conform to its obligations that are identified within the Pipeline Cost Recovery Agreement (PCRA), specifically but not exclusively in reference to our Letter of Credit.

Based on earlier correspondence, you seem to have the impression that the amount of the Letter of Credit concerning the pipeline is subject to negotiation. Rather, it is clearly dictated by the PCRA.

I look forward to your response.

Sincerely Yours,

Jim Grey, CEO
IGPC Ethanol Inc.

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

SENT BY COURIER

January 11, 2013

IGPC Ethanol Inc.
89 Progress Dr.
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey:

Further to our previous correspondence, we have not heard from you with regards to getting together to meet to address our concerns. Feel free to contact me at my cell number 519-709-7577.

Regards,

Natural Resource Gas Limited

Anthony H. Graat,
President

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

SENT BY COURIER

December 21, 2012

IGPC Ethanol Inc.
89 Progress Dr.
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey:

In response to your recent correspondence, as you know NRG has the duty and right to properly assess the financial viability of its' customers. Our concern over the financial viability of IGPC remains, as there is such a resistance from IGPC to provide any financial information to the contrary.

Regards,

Natural Resource Gas Limited

Anthony H. Graat,
President

IGPC

IGPC Ethanol Inc.

Rec'd Dec 21

December 19, 2012

Natural Resource Gas Ltd.
c/o Ayerswood Development
1299 Oxford Street East
London, ON
N5Y 2W5

Dear Mr. Graat,

On December 17, 2012, we received your letter dated December 11, 2012 indicating that IGPC had not responded to your first letter dated December 11, 2012. As such, it is necessary to set the record straight once again.

As you will recall, we contacted your solicitor, Mr. Thacker, on December 10, 2012 indicating that we had not had a response to our letter of December 3, 2012. In response, Mr. Thacker requested draft copies of the Letters of Credit. Following Mr. Thacker's request, IGPC received your first letter dated December 11, 2012. Upon receiving your letter, we forwarded it to Mr. Thacker to request that he speak with you. A copy of this email is attached to this letter. As we have not heard from either Mr. Thacker or yourself prior to your second letter received December 17, 2012 it is unclear whether you have spoken with Mr. Thacker.

We provided the two draft Letters of Credit from the Royal Bank of Canada to Mr. Thacker on December 12, 2012 and, as previously indicated, such Letters of Credit were identical to the Letters of Credit from Societe Generale that IGPC provided to NRG. The two Letters of Credit were even in the same amounts as originally provided in 2008 as NRG has in the past refused to permit IGPC to reduce the amount as specified in the Pipeline Cost Recovery Agreement. Despite the Letters of Credit being identical, we have received no response from NRG.

As such, IGPC found it necessary to expend significant additional resources to work around your intransigence. Every other entity from whom IGPC made a similar request to replace a Letter of Credit as part of the refinancing was co-operative and readily agreed to the replacement. The demand for confidential financial information to which you are not entitled in your prior

89 Progress Drive, P.O. Box 205, Aylmer ON N5H 2R9 • Tel. 519.765.2575 • 866.211.0435 • Fax 519.765.2775

letter and your silence regarding what should be the routine replacement of two Letters of Credit continue NRG's pattern of obstructionist behaviour.

We will be forwarding this correspondence to the Ontario Energy Board as further evidence that NRG does not intend to adhere to the terms of the Pipeline Cost Recovery Agreement or Gas Delivery Contract and NRG's refusal to provide distribution service to IGPC.

Regards,

Jim Grey, CEO
IGPC Ethanol Inc.,

cc: Mr. L. Thacker
Mr. M. Millar, OEB
Ms. K. Walli, OEB

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

SENT BY COURIER

December 17, 2012

IGPC Ethanol Inc.
89 Progress Dr.
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey:

We have received no response to our letter dated December 11, 2012 to you regarding your refinancing with the Royal Bank of Canada.

We assume that the matter is no longer urgent and you will be in touch with us in due course to set up a meeting to discuss the matter.

We have enclosed a copy of your solicitors email for your reference.

Regards,

Natural Resource Gas Limited

Anthony H. Graat,
President

Encl.

Natural Resource Gas Limited
39 Beech St. E., PO Box 307, Aylmer On N5H 2S1

SENT BY COURIER

December 11, 2012

IGPC Ethanol Inc.
89 Progress Dr.
Aylmer, ON N5H 2R9

Attention: Mr. Jim Grey
Chief Executive Officer

Dear Mr. Grey:

We are in receipt of your request to exchange NRG Letter of Credit to a new lender Royal Bank of Canada. As you may know the Christmas season is a busy time of year for everyone, including our professional advisors and others.

NRG has been unable in the past to obtain an accurate assessment of IGPC financing. As you may understand that is not an acceptable position for NRG to be in. We would ask you and or your financial advisors to meet with our people to better understand IGPC's financial position.

It was not last week that IGPC would have started negotiations to review their banking arrangement but, as they have done in the past, they leave it until the last minute then attempts to blame NRG for delays.

IGPC states in their letter of credit that the amount of the letter of credit is not correct but we will deal with that later and maybe just another lawsuit.

As always, IGPC final position is **"not let's sort this out and discuss the issues it is rather, do it now and IGPC is not interested whether NRG has any questions or concerns."**

Amongst other issues is "Who will pay for the review cost of lawyers and accountants?" IGPC obviously chooses when dealing with NRG not to have to explain anything, to anyone, at anytime for any reason

It appears that IGPC believes that NRG works for IGPC only. The fact is that IGPC is NRG's customer and NRG operates it business within normal business practices to protect its other customer s and shareholders.

It is NRG's position, that it has a duty to protect its customers and shareholders and when NRG has a full understanding of IGPC's financial position, it will certainly co-operate in any way possible to accommodate IGPC.

Regards,

Natural Resource Gas Limited

Anthony H. Graat,
President

NO ANOMALOUS CAPITAL/O&M EXPENDITURES FORESEEN

NRG has no major capital expenditures planned in the next two years, and does not foresee any anomalous operations and maintenance ("O&M") expenses. In addition, NRG is not aware of any major customer additions or losses. Given the anticipated "steady state" of NRG at least for the next two years, extending NRG's existing IR Plan is appropriate.

Board's Stated Conditions for Annual IR Adjustments

At Exhibit C, Tab 2, Schedule 1 of this pre-filed evidence, the three alternative rate options created by the Board as part of its Renewed Regulatory Framework are briefly outlined (4th Generation IR, Custom IR, Annual IR Index).

The Annual IR Index alternative, if selected by a distributor, involves the distributor simply adjusting rates by an Annual Adjustment Mechanism (without a cost-of-service application). As stated by the Board:

> The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. ... The annual rate adjustments are designed to reflect 'steady-state mode' operations – that is, rate adjustments will be comparatively minor.
>
> Distributors, who apply under this method for 2014 rates or later, must have had a cost of service hearing in 2008 or later. The Board also expects that a distributor applying under this method will not be exceeding its approved annual ROE by more than 300 basis points. ...
>
> (OEB, *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, pp. 20-21)

NRG's Rate Base and Planned Capital Expenditures

(a) General

As of September 30, 2013, the net book value ("NBV", based on averages) of NRG's distribution system (without the dedicated IGPC Pipeline) was within $5,600 of NRG's NBV for the Test Year used in NRG's last cost-of-service proceeding (EB-2010-0018). As of March 31, 2014, the NBV figure was within $9,000 of that Test Year. So NRG's rate base today is virtually identical what it was four years ago when it filed its pre-filed evidence in EB-2010-0018.

The depreciation of NRG's system (again, without the IGPC Pipeline) is approximately $70,000 monthly. This means that NRG could make approximately $960,000 of capital expenditures annually and remain in a relatively steady state from a rate base perspective. NRG believes this to be sufficient for the next two years. Of course, any material changes to NRG's expectations in respect of capital expenditures in the next two years could be safeguarded by the Z-factor and off-ramp.

(b) Rate 6 (IGPC) Rate Base

In previous proceedings, IGPC had mentioned that it would expect its Rate 6 to decrease at NRG's next cost-of-service, given that the dedicated IGPC Pipeline (which only IGPC uses) will depreciate over time. This would reduce the cost of capital associated with the IGPC Pipeline, and potentially the allocation of certain expenses and taxes (e.g., insurance, O&M, and property taxes) as between the Rate 6 assets (i.e., the IGPC Pipeline) and NRG's integrated distribution system (serving all other rate classes).

NRG has calculated the distribution cost savings flowing from a decreased rate base, and those amount to $71,000 per year (or $142,000 for the two-year extension period covered by this application), which NRG considers immaterial to IGPC's operating expenses. As for the reduction in other costs, in the absence of a full blown cost-of-service proceeding with a cost allocation study, it is very difficult to estimate whether these other costs would be and how their allocation would impact the costs to IGPC.

In addition to being immaterial, NRG is making this Application on the basis that the current IR Plan is operating in a way that is providing NRG with sufficient revenues to cover its costs (capital and O&M) and provide it with a fair return. NRG will continue to manage its capital and O&M expenditures on an "envelope" basis. The only way for this Application to proceed in a reasonable manner is to refrain from examining individual rate base/capital items (such as Rate 6's declining rate base) or individual O&M line items (see section below).

Steady-State O&M Expenses/Revenues Anticipated

As with its capital expenditures, NRG is not expecting any anomalous O&M expenditures or revenue fluctuations (i.e., loss or gain of material new customer load).

As noted above, NRG will continue to manage its O&M expenses on a global basis, with individual O&M line items varying from year-to-year.

FINANCIAL INFORMATION/SECURITY FROM IGPC

IGPC operates an ethanol plant in Aylmer, and is by far NRG's largest distribution customer (accounting for approximately 25% of NRG's distribution revenue). NRG has concerns about IGPC's ability to operate profitably and continue to take natural gas from NRG beyond 2016. As a result, NRG is seeking information and security from IGPC to ensure that NRG's other ratepayers are not responsible for any undepreciated capital cost associated with the IGPC Pipeline.

IGPC's Reliance on Operating Grants

Based on IGPC's financial statements, IGPC appears to be heavily reliant on two operating grants in order to operate profitably: (a) an "ecoEnergy for Biofuels" operating grant, managed by Natural Resources Canada ("NRCan"); and (b) an operating grant from the Ontario Ministry of Agriculture, Food and Rural Affairs ("OMAFRA"). The operating grant amounts vary modestly from year-to-year (being dependent on production volumes), but both are material to IGPC's revenues. The provincial operating grant from OMAFRA appears to be slightly greater than the NRCan grant. For example, in fiscal 2012, the provincial OMAFRA operating grant was $14.9 million and the federal NRCan grant was $12.4 million.

IGPC's financial statements indicate that these grants are set to expire in 2016 (see Exhibit C, Tab 4, Schedules 2 through 5). Specifically: (a) the provincial operating grant expires at the calendar year end of 2016; and (b) the federal operating grant appears to also expire at calendar year end, but the notes to IGPC's financial statements are not as precise (see note 15 of IGPC's 2011 financial statements at Exhibit C, Tab 4, Schedule 4). Moreover, as of February 2013, the federal government appears to have cancelled the NRCan "ecoEnergy for Biofuels" program, with no further applications being received after 2010 and no committed grant money paid out beyond 2017 (see Exhibit C, Tab 4, Schedule 6).

The loss of IGPC's operating grants is of significant concern to NRG because IGPC's annual net income has consistently been far less than the sum of its two annual operating grants (see the Consolidated Statement of Operations and Retained Earnings/Deficit at Exhibit C, Tab 4, Schedules 2 through 5 inclusive):

IGPC's Fiscal Year Ending September 30	IGPC's Net Income	IGPC's Operating Grants	Loss Without Grant
2009	$4.7 million	$26.8 million	**$22.1 million**
2010	$12.4 million	$27.1 million	**$14.7 million**
2011	$11.7 million	$28.7 million	**$17.0 million**
2012	$11.9 million	$27.5 million	**$15.6 million**

In the absence of the operating grants, IGPC would have operated at a loss in every year from 2009 to 2012. Consequently, NRG is concerned about IGPC's profitability and its ability to take gas from NRG post-2016 (when the operating grants expire).

<u>Milestone Events Pre-2016</u>

Between now and the expiry of IGPC's operating grants in 2016, there are two milestone dates:

- <u>April 2015 (Gas Delivery Contract Termination)</u>: The Gas Delivery Contract ("GDC") between IGPC and NRG terminates on April 30, 2015 (see Exhibit D, Tab 1, Schedule 2). Under the GDC, IGPC is required to deliver a minimum annual volume of

33,416,618 m^3 of natural gas to NRG. IGPC has not provided NRG with any indication as to whether it will renew the GDC, and if so at what minimum annual volume, and for how long.

- November 2015 (Letter of Credit Expiry): IGPC's Delivery Letter of Credit for the current undepreciated capital cost of the IGPC Pipeline expires on November 30, 2014, although it will be deemed to automatically extend to November 30, 2015 unless 30 days notice is provided to NRG (see Exhibit D, Tab 1, Schedule 4). IGPC has agreed to provide NRG with a new letter of credit (expiring November 30, 2015). Beyond November 30, 2015, NRG has no information from IGPC as to its operational plans.

Cost Responsibility for Undepreciated Capital Costs

It is imperative that NRG's other ratepayers are protected from bearing the cost of any undepreciated capital cost/net book value of the IGPC Pipeline (the "Pipeline NBV") in the worst-case scenario where IGPC is not able to purchase distribution services from NRG after 2016, but before the IGPC Pipeline is fully depreciated in 2028.

As the Board knows, the IGPC Pipeline is not integrated with NRG's existing system. The IGPC Pipeline is a dedicated steel pipeline that was constructed solely to serve IGPC. It is an expensive asset, and any cost shifting resulting from stranding that asset would be a significant cost to NRG's other 8,000 customers.

The starting point for ensuring that NRG's other ratepayers are protected is to require IGPC to provide NRG with the following information:

- updated financial statements;
- information as to the status and likely renewal of IGPC's operating grants;
- information about IGPC's business plans if the operating grants are not extended or renewed beyond 2016; and,
- information about IGPC's natural gas requirements (volume and term) upon expiration of the current Gas Delivery Contract in April 2015.

Based on this information, and the expiration of the letter of credit as of November 2015, the Board will then have sufficient information to order security in a form that fully protects NRG and its other customers from bearing any undepreciated capital costs associated with the IGPC Pipeline beyond November 2015.

NATURAL RESOURCE GAS LIMITED

GAS DELIVERY CONTRACT

TYPE OF SERVICE:

X Firm Demand and Commodity
__ Interruptible Demand and Commodity
__ Combined Firm and Interruptible Demand and Commodity

DATE OF CONTRACT: January 30, 2007

RATE CLASS: 3

PARTIES TO CONTRACT:

NATURAL RESOURCE GAS LIMITED, (the "Utility"),

and

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC. (the "Customer"),

PART 1 - PURCHASE AND SALE

The Customer agrees that it will receive from the Utility all of the gas that it uses for the processes described below and which is delivered at the Delivery Points (except during periods of curtailment, discontinuance or force majeure as set out in this Contract) up to the maximum daily and hourly maximum volumes set out in Part 2. This gas supply will be delivered in accordance with Rate BT1 (a copy of which is attached) for the Customer's share of the transportation costs associated with supplying its own gas.

Subject to the provisions of this Contract and the Rate 3 schedule in Schedule A and any subsequent amendments approved by the Ontario Energy Board during the term of this Contract, the Customer shall purchase its own gas to be delivered by the Customer to Union Gas Limited, by Union Gas Limited to the Utility, and by the Utility to the Customer (including any gas in excess of the Customer's minimum annual volume which the Customer requests and which the Utility has agreed to deliver) and the Utility shall deliver such gas to the Customer.

Delivery Point (to Customer) - Ethanol Facility, Aylmer Industrial Park

Processes: Ethanol production, grain drying and space heating

Gas Quality:

The gas received by the Utility and delivered to the Customer (at prevailing pressure and temperature in the Utility's pipeline at the Point of Receipt) shall be commercially free from sand, dust, gums, crude oils, lubricating oils, liquids, chemicals or compounds used in the production, treatment, compression or dehydration of the gas or any other substance in sufficient quantity so as to render the gas toxic, unmerchantable or cause injury to or interference with the proper operation of the lines, regulators, meters or other appliances through which it flows.

PART 2 - MAXIMUM DAILY VOLUME AND MINIMUM ANNUAL VOLUME

The maximum volume of firm gas the Utility is required to deliver to the Customer in any day (which shall be a 24 hour period commencing 10:00 a.m. Eastern Standard Time) shall not exceed 108,188 m^3 (the "Firm Contract Demand") and in any hour shall not exceed 4507.83 m^3, being 1/24th of the Firm Contract Demand. Should the Customer consume more than 4,508m^3/hour during any hour and such excess consumption is adversely impacting the Utility's ability to operate its distribution system, the Utility may curtail service to a volume of 4,508 m^3/hour. Consumption in excess of 4,508 m^3/hour by the Customer shall not be considered to be a breach of this Contract.

Should the Customer exceed the Firm Contract Demand in any day during the contract year, then this higher number will be the new Firm Contract Demand for the entire year and any months billed previously at the lower amount will be rebilled using the higher Firm Contract Demand. In the event the Customer exceeds the Firm Contract Demand and the Utility, pursuant to this section, increases the Firm Contract Demand then the Utility shall be obligated to deliver such higher volume on a firm basis, and the hourly volume specified herein shall be adjusted accordingly, subject to being able to make any arrangements with Union Gas that may be required.

The Minimum Annual Volume of gas the Customer is required to accept and pay for in any contract year or any anniversary thereof shall be 33,416,618 m^3.

PART 3 - RATE

Subject to the provisions of the paragraph 1.2 of the General Terms and Conditions attached as Schedule B, the Customer shall pay for all natural gas delivered under this Contract at such rates and charges (including, without limitation, any applicable administration charge, minimum bill per month, penalty for late payment and unauthorized overrun gas rate) and as are applicable to or for such service in accordance with the provisions of the Utility's Rate 3 schedule in effect at any time during the term of this Contract.

Monthly Customer Charge:	$ 150.00
Firm Delivery Rate:	$ 0.037310 per m^3

Firm Demand Rate: $ 0.255904 per m^3 of Firm Contract Demand

If the Utility, pursuant to Part 5 of this Contract, or due to Force Majeure as described in the General Terms and Conditions, fails or is unable to deliver the amount of firm gas which the Customer desires to take during any one or more days in a month, up to the Customer's Firm Contract Demand in effect on such days, then the minimum bill for that month shall be reduced by an amount equal to the Firm Delivery Rate applied to the volume by which the Firm Contract Demand exceeds the volume of gas delivered to the Delivery Point on such a day, for each day in the month in which the inability to deliver continues.

The Utility acknowledges that the volumes in this agreement are significantly greater than the volumes delivered to existing Rate 3 customers and that a new rate may be more appropriate for the Utility and the Customer. The Utility has committed to developing a new rate for the Customer, to be included in the Utility's Fiscal 2008 rate application which is anticipated to be filed with the Ontario Energy Board in April 2007.

PART 4 - POINT OF DELIVERY

The point of delivery of all gas by the Utility is at the outlet of the Utility's metering equipment at the Customer's Ethanol Facility. The Utility shall at no time assume title to the gas that the Customer is supplying into the Utility's distribution system. The Utility agrees to deliver gas at the outlet of its metering equipment at a minimum pressure of 60 psig or 420 kPa.

PART 5 - PRIORITY OF SERVICE

In the event of actual or threatened shortage of natural gas due to circumstances beyond the control of the Utility, or when curtailment or discontinuance of supply is ordered by an authorized government agency, the Customer shall at the direction of the Utility, curtail or discontinue use of gas during the period specified by the Utility so as to safeguard the health and safety of the public. Such curtailment or discontinuance shall be made on a prorated basis as may be ordered by a government agency among all industrial Rate 3 customers. The Utility shall not be liable for any loss of production or for any damages whatsoever by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

PART 6 - CURTAILMENT OR DISCONTINUANCE OF SERVICE

Firm service under this Contract will be provided up to the Firm Contract Demand.

Notice of curtailment or discontinuance of service may be conveyed by telephone, in person, by mail, facsimile or email. If notice is conveyed by telephone or in person then the Utility shall at the earliest possible time thereafter confirm in writing the details of notice and provide the reasons for the curtailment or discontinuance and the anticipated duration of the curtailment if the curtailment or discontinuance is continuing at the time of the written notice.

Service will be resumed as soon as possible when these conditions cease to be operative.

PART 7 - TERM

Unless deemed to commence otherwise, this Contract shall commence upon Commercial Operation of the Customer's ethanol facility (the "Commencement Date") and terminate the day immediately prior to the seventh anniversary of the Commencement Date.

Commercial Operation shall mean the date upon which a professional engineer duly qualified to practice engineering in Ontario procured by the Customer provides a certificate that the Customer's ethanol facility has been completed in all material respects excepting punch list items that do not materially and adversely affect the ability of the Customer to operate the ethanol facility. In the event that Commercial Operation has not been achieved prior May 1, 2008 then the Commencement Date shall be deemed to be May 1, 2008. In the event Commercial Operation is prior to April 1, 2007, the Commencement Date shall be deemed to be April 1, 2007.

The Customer shall notify the Utility of the Commencement Date at least 30 days in advance of the Commencement Date.

The Utility's Rate 1 shall apply to any gas volumes delivered prior to the Commencement Date.

PART 8 – RE-OPENER

In the event the market for ethanol or dried distillers grains is materially and adversely impacted the Customer may give written notice to Utility that it wishes to renegotiate this Contract. Upon the written request of the Customer, the Parties shall within ten (10) Business Days enter into good faith negotiations to amend this agreement to preserve the original intent of the bargain of providing economical delivery service to the Customer without undue burden or risk to the Utility or the other ratepayers of the Utility and recognizing the need for the Customer to maintain satisfactory financial assurances with the Utility. The term of any renegotiated agreement would only commence on an anniversary date of this Contract, unless otherwise agreed.

PART 9 - GENERAL TERMS AND CONDITIONS

The General Terms and Conditions attached as Schedule B form part of this Contract.

PART 10 – SECURITY DEPOSIT

Prior to the commencement of delivery of gas pursuant to this Agreement, the Customer shall provide a security deposit to the Utility in the amount of one month's delivery charge using the applicable Rate at the Commencement Date. The security deposit may be in the form of a letter of credit, guarantee or other mutually agreeable method of providing financial assurance. The amount of any security deposit shall be subject to adjustment on an annual basis on the anniversary of the Commencement Date using the applicable rate on such date.

The maximum amount of the security deposit will be equal to:

Security Deposit = Monthly Customer Charge + Demand Charge + Delivery Charge

Where:

Monthly Customer Charge = amount specified in Part 3

Demand Charge = Firm Contract Demand x Firm Demand Rate

Delivery Charge = Firm Delivery Rate x Firm Contract Demand x 48

The Utility shall not be entitled to draw upon the security deposit while the Customer is in compliance with the terms of this Agreement and shall not be entitled to draw upon security deposit during any dispute, unless such dispute has been finally resolved and the Buyer has not made payment with ten (10) Business Days of the final resolution of such dispute.

PART 11 – INVOICING & PAYMENT

All invoices from Utility to Buyer will delivered to Customer's address as noted below. Monthly invoices will be prepared and in accordance with the General Terms and Conditions and the Customer shall pay such invoices within the time frames provided in the General Terms and Conditions.

In the event the Customer does not pay the invoice within the timeframes provided, then the Utility shall provide notice to the Customer that the Customer is not in compliance and the Customer shall have three (3) Business Days to remedy such non-payment. In the event the Customer does not make payment within three (3) Business Days of receiving notice then Utility shall be entitled to draw upon the security deposit for the amount owed.

In the event of a dispute regarding the amount of any invoice delivered by the Utility to the Customer, the Customer shall pay the undisputed portion within the time required in the General Terms and Conditions. The Customer shall at the time of payment of the undisputed portion of the invoice give notice to the Utility of the dispute and the reasons it is disputing such amount. Upon receipt of such notice of disputed amount, the Parties shall enter into good faith discussions to resolve the dispute. In the event the Parties are unable to resolve the dispute within fifteen (15) Business Days then the Customer may refer the matter for dispute resolution. Disputes relating to metering will be subject to the dispute resolution mechanisms established pursuant to the *Electricity and Gas Inspection Act*. Disputes within the jurisdiction of the Ontario Energy Board will be referred to the Ontario Energy Board for resolution. The Customer may refer all other disputes for arbitration under the Arbitration Act 1991 (Ontario) before a single arbitrator. If the Customer has not given written notice that the Customer is referring the dispute for resolution within five (5) Business Days, the Customer will be deemed to have abandoned the dispute and shall pay any amount still owing within three (3) Business Days.

Monies found to be owing to the Utility at the resolution of the matter shall be paid by the Customer within five Business Days of such final resolution. If upon resolution of the matter, the amount owed by the Customer is less than the amount originally withheld by the Customer, then interest will not be calculated during the time period prior to the resolution of the dispute.

The Utility shall also be entitled to recover its Ontario Energy Board approved late payment charge for any late payment, including any payment that is unsuccessfully disputed by the Customer.

This Agreement is subject to the consent of the Customer's Lenders. The Customer agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Customer. The Customer shall waive this condition in writing.

PART 12 - NOTICE OF COMMUNICATION

Except for the notice for curtailment of service set out in Part 6 above, any notice or other communication required to be given by either party to this Contract to the other shall be deemed to have been given 72 hours after such notice of communication shall have been mailed in a postage prepaid envelope addressed, in the case of notice to the Utility, to it at:

Natural Resource Gas Ltd.
39 Beech St. E.,
P.O. Box 307,
Aylmer, Ontario N5H 2S1

Telephone: 519-773-5321 Facsimile: 519-773-5335

Or in the case of notice to the Customer, to it at:

Integrated Grain Processors Co-operative Inc.
701 Powerline Road
Brantford, Ontario N3T 5L8

Telephone: (519) 752-0447 Facsimile: (519) 752-1887

or in each case to such other address as the particular party may furnish to the other from time to time during the term of this Contract, provided that any such notice or other communication may be given by delivery at the above addresses and shall be deemed to have been given at the time of such delivery. All invoices from Utility to Customer will be hand delivered to Customer's address as noted above.

IN WITNESS WHEREOF, the parties hereto have executed this Contract.

NATURAL RESOURCE GAS LIMITED

By:

Name: Mark J. Bristoll
Title: President
I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE LTD..

Per:

Name: Tom Cox
Title:
I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

Per:

Name: Brent McBlain
Title:
I have authority to bind the corporation.

of such delivery. All invoices from Utility to Customer will be hand delivered to Customer's address as noted above.

IN WITNESS WHEREOF, the parties hereto have executed this Contract.

NATURAL RESOURCE GAS LIMITED

By:

Name: Mark J. Bristoll
Title: President
I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE LTD..

Per:

Name: Tom Cox
Title:
I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

Per:

Name: Brent McBlain
Title:
I have authority to bind the corporation.

Schedule A

OEB APPROVED RATE SCHEDULE

[TO BE INSERTED]

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 25.5904 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 3.7310 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 9.2249 cents per m^3 and not to be less than 6.0992 per m^3.

d) Gas Supply Charge (if applicable)

See 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 3.3853 cents per m^3 for firm gas and 5.7536 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 6.3515 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: April 01, 2007
Implementation: All bills rendered on or after April 01, 2007
EB-2007-0048

NATURAL RESOURCE GAS LIMITED GAS DELIVERY CONTRACT

SCHEDULE B - GENERAL TERMS AND CONDITIONS

PART 1 – RATES

1.1 Bills are issued monthly, being due when rendered in accordance with the provisions of the gas delivery contract and the approved rate schedule. If payment in full is not received within 15 days of rendering the bill, any amount owing shall be increased by 1.5% on the next bill.

1.2 In the event of any increase,

(a) in the cost of gas to the Utility under its gas purchase contracts;

(b) in the cost of gas to the Utility resulting from the application of any valid law, order, rule or regulation of any legislative body or duly constituted authority now or hereafter having jurisdiction;

(c) in the costs of the Utility resulting from any changes in, or the imposition of any taxes, excises or duties by any governmental authority during the lifetime of this contract, on the importation, transmission, storage, purchase or sale of gas; or

(d) in the charges or rates approved or fixed by the Ontario Energy Board for the delivery or sale of gas by the Utility to the Customer, including retroactive rate increases authorized by the Ontario Energy Board.

then to the extent that such increases in the case of (a), (b) or (c) above are paid by the Utility on the gas delivered to the Customer, or such increase in the case of (d) above is ordered by the Ontario Energy Board to be charged to the Customer, the rates to be paid by the Customer to the Utility, pursuant to the gas delivery contract, shall be increased accordingly for all gas delivered subsequent to that increase in costs or charges, provided that the increased rates shall not exceed rates fixed by order of the Ontario Energy Board from time to time.

1.3 In the event the terms and conditions of the agreement between Utility and Customer are changed by Order of the Ontario Energy Board, such changed terms and conditions shall be deemed to be in effect between the Utility and the Customer.

PART 2 – UNAUTHORIZED OVER-RUN GAS PENALTY

2.1 If, on any day, the Customer takes without the Utility's advance approval, a volume of gas in excess of the maximum hourly or daily quantity of firm or interruptible gas which the Utility is obligated to deliver to the Customer on such day, or if, on any day, the Customer fails to comply with any curtailment order of the Utility reducing either the Customer's hourly or daily take of gas, the volume of gas taken in excess of the Utility's maximum delivery obligation or curtailed maximum delivery obligation shall constitute unauthorized over-run gas.

2.2 In the event the Customer on any day takes a volume of gas constituting unauthorized over-run gas:

(a) the Utility may curtail gas service to the Customer during such a day when required to avoid adverse impacts to the Utility's distribution system;

(b) the Customer shall pay the Utility a penalty as stipulated in the Rate 3 rate schedule.

PART 3 – METERING AND SERVICE

3.1 The Utility agrees to install, operate and maintain measurement equipment of suitable capacity and design to measure the gas supplied.

3.2 The measurement and regulating equipment shall be installed on the Customer's premises at a site located as near as possible to the point of utilization in accordance with safety regulations.

3.3 Each party shall have the right to enter the measurement and regulating location at any reasonable time and shall have the right to be present at the time of installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting of measurement equipment.

3.4 The Utility's measurement equipment shall be examined by the Utility at least once every nine months and, if requested, in the presence of a representative of the Customer, but the Utility shall not be required as a matter of routine to examine such equipment more frequently than once in any nine month period.

3.5 All natural gas delivered to the Customer shall be measured utilizing equipment and procedures that conform to the *Electricity and Gas Inspection Act* and regulations, and specifications authorized by the Act and regulations.

PART 4 – EQUIPMENT

4.1 The title to all service pipes, meters, regulators, attachments and equipment placed on the Customer's premises and not sold to the Customer shall remain with the Utility, with right of removal, and no charge shall be made by the Customer for use of premises occupied thereby, and the Customer agrees to be responsible for any loss or damage thereto resulting from wilful or negligent acts of the Customer or its agents or employees or persons acting under the authority of or with the permission of the Customer.

PART 5 – FORCE MAJEURE

5.1 In the event that either the Customer or the Utility is rendered unable, in whole or in part, by Force Majeure, to perform or comply with any obligation or condition of this Contract, then the obligations (other than the obligations to make payment of money then due) of both parties so far as they are directly related to and affected by such Force Majeure, shall be suspended during the continuance of the Force Majeure.

5.2 The party claiming Force Majeure shall give Notice, with full particulars, to the other party as soon as possible after the occurrence of Force Majeure.

5.3 The party claiming Force Majeure shall also give Notice to the other party as soon as possible after the Force Majeure is remedied in whole or part.

5.4 Force Majeure means:

(a) Acts of God, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to its machinery or equipment or lines of pipe;

(b) freezing or failure of wells or lines of pipe; curtailment of firm transportation or firm storage by other natural gas service providers;

(c) strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections, civil disturbance, acts of terrorism, wars, arrests or restraint of governments and people;

(d) any laws, orders, rules, regulations, acts of any government body or authority, civil or military;

(e) any act or omission by parties not controlled by the party claiming Force Majeure; and

(f) any other similar causes not within the control of the party claiming Force Majeure

which by the exercise of due diligence such party is unable to prevent or overcome. The party claiming Force Majeure shall make reasonable efforts to avoid, or correct the Force Majeure and to remedy the Force Majeure once it has occurred in order to resume performance.

5.5 Neither party shall be entitled to claim force majeure if any of the following circumstances prevail:

(a) the failure resulting in a condition of force majeure was caused by the negligence of the party claiming suspension;

(b) the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation);

(c) the party claiming suspension failed to resume the performance of such conditions or obligations with reasonable dispatch;

(d) the failure was caused by lack of funds; and

(e) the party claiming suspension did not give to the other party the required notice as soon as possible after determining or within a period within which it should have determined, acting reasonably, that the occurrence was in the nature of force majeure and would affect its ability to observe or perform any of its conditions or obligations under the Contract.

5.6 During a Force Majeure declared by the Utility, the Customer will be responsible for any commodity charges and will only be relieved of the demand charges applicable to that part of the services not available to the Customer as a result of the Force Majeure. The Utility will not be responsible for any charges by any other natural gas service providers.

5.7 During a Force Majeure declared by the Customer, all demand charges and all commodity charges otherwise payable under this Contract will continue to be payable. The Minimum Annual Volume shall be reduced in the same proportion as the number of days of Force Majeure the number of days in a contract year.

5.8 The term of the Gas Delivery Contract shall be extended by the length of any Force Majeure event.

PART 6 – AGREEMENTS OF INDEMNITY

6.1 The Utility and the Customer shall save harmless and indemnify the other from any injury, loss or damages to persons or property caused by its negligence or wilful misconduct or by the negligence or wilful misconduct of its agents or employees or persons acting under its authority or with its permission.

PART 7 – MISCELLANEOUS

7.1 No waiver by either party of any one or more defaults by the other in the performance of any provisions of the contract shall operate or be construed as a waiver of any future default or defaults, whether of a like or different character.

7.2 This contract shall be interpreted, performed and enforced in accordance with the laws of the Province of Ontario.

7.3 No additions, deletions or modification of the terms and provisions of this contract shall be effective except by the execution of a new contract.

7.4 This contract shall be binding upon, and inure to the benefit of the parties hereto and their respective successors and assigns but shall not be assigned or be assignable by the Customer without the prior written consent of the Utility. The Utility agrees that such consent shall not be unreasonably withheld. For greater certainty an assignment by way of security to the Customer's lenders shall be considered reasonable.

7.5 Any gas purchased by the Customer hereunder shall not be resold or otherwise used by a third party.

This **PIPELINE COST RECOVERY AGREEMENT** ("Agreement"), made as of the 31st day of January, 2007.

BETWEEN:

NATURAL RESOURCE GAS LIMITED,
a corporation formed under the laws of Ontario.
(the "Utility")

- and -

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.,
a co-operative corporation formed under the laws of Ontario.
(the "Customer")
(collectively the "Parties")

RECITALS:

WHEREAS the Customer is developing an ethanol facility (the "Customer Facility") in the Town of Aylmer, Ontario;

AND WHEREAS the Utility must expand its current natural gas distribution infrastructure to deliver natural gas to the Customer Facility to meet the volume, pressure and delivery requirements of the Customer;

AND WHEREAS the Utility has a franchise agreement to distribute natural gas in the Town of Aylmer;

AND WHEREAS the Utility has entered or will enter into an agreement with Union Gas Limited to install new facilities or modify existing facilities to supply the Utility with natural gas, such that Union Gas Limited will be capable of meeting the total supply requirements of the Utility, including the supply needs of the Customer;

AND WHEREAS the Utility and Union Gas Limited have reached an understanding regarding the Utility Connection Facilities crossing the Union Gas Limited franchise area;

AND WHEREAS the Customer has paid to the Utility a deposit of $130,000.00 against any Aid-to-Construct that may be owed to the Utility;

AND WHEREAS the Utility and the Customer have entered into an agreement dated January 31, 2007, as the same may be amended, modified, supplemented or restated (the "Gas Delivery Contract") providing for the Utility to deliver natural gas to the Customer Facility, among other things;

AND WHEREAS the Customer, or its representative, will be purchasing the Customer's gas directly and arranging for transportation, and the Utility and the Customer will enter into a Bundled T-Service Receipt Contract;

AND WHEREAS the Utility has determined that approximately 28.53km of NPS 6 steel pipeline and related facilities are required to be installed to deliver natural gas to the Customer Facility;

AND WHEREAS the Customer has requested and the Utility has agreed to construct approximately 28.53km of NPS 6 steel pipeline and related facilities (the "Utility Connection Facilities") and to arrange with Union Gas Limited for the construction by Union for facilities required to complete the connection between the Utility Connection Facilities and the Union Gas Limited system (the "Union Gas Connection Facilities"), to deliver natural gas from the Union Gas Limited system to the Customer Facility, on the terms and conditions set forth in this Agreement; and

IN CONSIDERATION of the mutual covenants contained herein, the receipt and sufficiency of which is hereby acknowledged and accepted, the Parties to this Agreement agree as follows:

ARTICLE I – ATTACHMENTS AND INTERPRETATION

1.1 The following are hereby incorporated into and form part of this Agreement:

(a) Schedule A - Pipeline Work

(b) Schedule B - Project Map

1.2 For the purpose of this Agreement:

(a) "Actual Aid-To-Construct" means the Aid-To-Construct calculated by the Utility using the Actual Capital Cost, as provided for in Article III;

(b) "Actual Capital Cost" means the reasonable actual Capital Cost, as provided for in Article III;

(c) "Aecon" means Aecon Utilities - A Division of Aecon Construction Inc., or any successor thereto;

(d) "Aid-to-Construct" means the amount by which the Capital Cost exceeds the revenue recovered by the Utility through rates, as calculated in accordance with EBO 188;

(e) "Applicable Law" means all federal, provincial, county, municipal or local laws, by-laws, statutes, rules, regulations ordinances, directives, or any decisions of a Governmental Authority.

(f) "Business Day" means a day, other than a Saturday or Sunday or statutory holiday in the Province of Ontario or any other day on which banking institutions in Ontario are not open for the transaction of business;

(g) "Capital Cost" means the total capital cost of the Utility Connection Facilities and the Union Gas Aid-to-Construct;

(h) "Construction" means construction and installation of the Utility Connection Facilities;

(i) "Construction Agreement" means the agreement between the Utility and a contractor for the completion of the Construction;

(j) "Cubic metres" or "m^3" means the volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre;

(k) "Customer Facility" means the ethanol facility proposed to be built and operated by the Customer in the Town of Aylmer with an output capacity of approximately 150 million litres of ethanol annually;

(l) "Customer Meter Facility" means the Utility's equipment to measure the gas consumed by the Customer, located at the Customer Facility, and includes but is not limited to all meters, pressure regulators, valves, fittings and communications equipment, and forms part of the Utility Connection Facilities;

(m) "EBO 188" means the Final Report of the Board, dated January 30, 1998 regarding the economic evaluation of the expansion of natural gas systems;

(n) "Event of Default" means either a Customer Event of Default or a Utility Event of Default;

(o) "Governmental Authority" means any federal, provincial, municipal or local government, parliament or legislature, or any regulatory authority, agency or tribunal, commission, board or department of any such government, parliament or legislature or any court or other law, regulation or rule-making entity having jurisdiction in the relevant circumstances;

(p) "GST" means the goods and service tax exigible pursuant to the *Excise Tax Act* (Canada) as amended from time to time;

(q) "Initial Estimated Aid-To-Construct" means the Aid-To-Construct calculated in accordance with EBO 188 using the Initial Estimated Capital Cost;

(r) "Initial Estimated Capital Cost" means the estimated Capital Cost provided by Aecon, including the Union Gas Aid-to-Construct;

(s) "In-Service Date" means the later of November 1, 2007 and the date on which the pipeline is able to deliver the full amount of the gas contemplated by the Gas Delivery Contract;

(t) "Insolvency Legislation" means the *Bankruptcy and Insolvency Act* (Canada), the *Winding Up and Restructuring Act* (Canada) and the *Companies' Creditors*

Arrangement Act (Canada) and the bankruptcy, insolvency, creditor protection or similar laws of any other jurisdiction (regardless of the jurisdiction of such application or competence of such law), as they may be amended from time to time.

(u) "Leave-to-Construct" means the application, decision, order or approval as the context requires pursuant to section 90 of the *Ontario Energy Act, 1998* as amended;

(v) "MMBTU" means one million British Thermal Units;

(w) "NPS" means nominal pipe size;

(x) "OEB" means the Ontario Energy Board or any successor organization;

(y) "Overhead" shall, to the extent not included in other consulting costs, include the reasonable engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items allocated to the Utility Connection Facilities;

(z) "Pipeline Work" means the work required to plan, design, construct, install, test and commission the Utility Connection Facilities and the Union Gas Connection Facilities;

(aa) "Prime Rate" means the prime rate of interest of the Bank of Nova Scotia;

(bb) "Revised Estimated Aid-To-Construct" means the estimated Aid-To-Construct calculated in accordance with EBO 188 using the Revised Estimated Capital Cost;

(cc) "Revised Estimated Capital Cost" means the estimated Capital Cost, using the most current information available, in accordance with Article III;

(dd) "Utility Connection Facilities" means the pipeline and ancillary facilities to be completed by the Utility to serve the Customer;

(ee) "Union Gas Aid-To-Construct" means the Aid-To-Construct payable to Union Gas Ltd. by the Utility in respect of the Union Gas Connection Facilities, calculated in accordance with EBO 188;

(ff) "Union Gas Connection Facilities" means the pipeline and ancillary facilities to be completed by Union Gas Limited upstream of the Utility Connection Facilities, that are necessary to serve the Customer.

ARTICLE II – REPRESENTATIONS AND WARRANTIES

2.1 The Customer represents and warrants to the Utility that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations under it;

(c) the execution, delivery and performance of the Agreement by it has been duly authorized by all necessary corporate action and does not result in a violation, a breach or a default under: (i) its charter or by-laws; (ii) any contracts or instruments to which it is bound; or (iii) any Applicable Law;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) this Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms; and,

(f) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution.

2.2 The Utility represents and warrants to the Customer that:

(a) it is duly incorporated, formed or registered (as applicable) under the laws of its jurisdiction of incorporation, formation or registration (as applicable);

(b) it has all the necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations under it;

(c) the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate action and does not result in a violation, a breach or a default under: (i) its charter or by-laws; (ii) any contracts or instruments to which it is bound; or (iii) any Applicable Law;

(d) any individual executing this Agreement, and any document in connection herewith, on its behalf has been duly authorized by it to execute this Agreement and has the full power and authority to bind it;

(e) this Agreement constitutes a legal and binding obligation on it, enforceable against it in accordance with its terms;

(f) no proceedings have been instituted by or against it with respect to bankruptcy, insolvency, liquidation or dissolution; and,

(g) the calculation of the Initial Estimated Aid-To-Construct has been completed in accordance with EBO 188.

ARTICLE III – CAPITAL COST AND AID-TO-CONSTRUCT

3.1 The Initial Estimated Capital Cost is estimated at $9,100,000.00, comprised of approximately $8,920,000.00 for the Utility Connection Facilities and $180,000.00 for the Union Gas Aid-To-Construct. The Initial Estimated Capital Cost is included in the Leave-to-Construct application filed by the Utility with the OEB.

3.2 Based upon the Initial Estimated Capital Cost and applying the Utility's current OEB-approved Rate 3 to a minimum annual volume of 33,416,618 m^3 and a firm contract demand of 108,188 m^3/day over a seven year period, the Initial Estimated Aid-to-Construct is $3,790,000.00, to be paid by the Customer.

3.3 The Customer shall make payments toward the Initial Estimated Aid-to-Construct, as follows:

(a) $130,000.00 on or before October 16, 2006, payment of which has been received and acknowledged;

(b) Prior to the award of the Construction Agreement, the amount of the monthly invoices provided by the Utility for reasonable internal, consulting and third party expenses incurred in the prior calendar month within fifteen (15) Business Days of receiving such invoice; and

(c) Payment, in advance as required by the Utility, of an amount equal to any required payment to be made by Utility for procuring the station material and pipe;

the total of which payments shall not exceed the Initial Estimated Aid-to-Construct.

3.4 Prior to the execution of the Construction Agreement, the Utility shall provide the Customer with a Revised Estimated Capital Cost and a Revised Estimated Aid-to-Construct, based on the most current information available at the time, including the successful bid for the Construction Agreement, calculated in accordance with EBO 188, and:

(a) The Customer shall pay the Utility an amount equal to the amount, if any, by which the Revised Aid-To-Construct exceeds the total of all payments made by the Customer to the Utility under Section 3.3. In the event that the amount paid by the Customer pursuant to Section 3.3 exceeds the Revised Estimated Aid-To-Construct then the Utility shall forthwith pay to Customer an amount equal to the payments made less the Revised Estimated Aid-To-Construct; and

(b) The Utility shall provide the Customer with a detailed written breakdown of the Revised Estimated Capital Cost including, but not limited to Overhead, engineering, surveying, consultant, legal, major materials (pipe, meters, major equipment, heating equipment costs), easement, internal and external construction and commissioning costs when it is available to the Utility and a copy of the cost breakdown for the Union Gas Connection Facilities as provided to the Utility by Union Gas Limited.

3.5 In the event that the Commencement Date under the Gas Delivery Contract is later than the In-Service Date, the Utility shall invoice and the Customer shall pay an amount equal to the Utility's reasonable debt financing costs incurred in each month between the In-Service Date and the Commencement Date under the Gas Delivery Contract.

3.6 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.

3.7 The Utility, in its sole discretion, may elect not to proceed any further with any of its obligations under this Agreement if the Customer fails to make any payment or provide any letter of credit required under this agreement until such payment or letter of credit is delivered by the Customer to the Utility and the Utility shall not be liable for any liabilities, damages, losses, payments, costs, or expense that may be incurred by the Customer as a result.

3.8 From the date required for any payment required by this Agreement, all unpaid amounts will bear interest at the rate of the Prime Rate plus 1.00% per annum payable quarterly on the last day of each calendar quarter.

3.9 The Utility shall use best efforts to minimize the actual Capital Cost, and shall advise the Customer of actual costs as incurred, in accordance with Article IV. At a minimum, the Utility shall ensure the award of the Construction Agreement is completed through a competitive tender process unless otherwise agreed to in writing by the Customer. The Utility shall ensure that the procurement of pipe, major equipment and appliances is done using a competitive quotation process wherever possible. The Utility shall inform the Customer where a competitive process is not utilized and provide an explanation as to why a competitive process is not required. Prior to committing to any expenditure in excess of $100,000.00, the Utility shall obtain the written consent of the Customer, such consent not to be unreasonably withheld.

3.10 The Utility shall request Union Gas Limited to provide it with the actual capital cost of the Union Gas Connection Facilities and the actual Union Gas Aid-to-Construct within 30 Business Days or other mutually agreeable timeframe of the pipeline being put into service.

3.11 The Customer and the Utility acknowledge that the Initial Estimated Capital Cost and the Revised Estimated Capital Cost may be different from the Actual Capital Cost incurred and the parties agree that the Actual Aid-to-Construct and Delivery Letter of Credit (as defined in Article VII) shall be adjusted based on an economic evaluation carried out in accordance with EBO 188.

3.12 The Customer reserves its rights to dispute the reasonableness of costs incurred in completing the Pipeline Work, provided that the Customer does so within 5 Business Days when such costs are provided by the Utility to the Customer.

3.13 Within forty-five (45) Business Days or some other mutually agreeable timeframe of the pipeline being put into service, the Utility shall provide the Customer with the Actual Capital Cost and Actual Aid-To-Construct, along with a summary of the information provided pursuant to Section 4.3 and copies of any invoices and supporting documentation not previously provided to Customer. If the Customer agrees with the Actual Capital Cost and Actual Aid-To-Construct, and

(a) if the Actual Aid-To-Construct is greater than the Revised Estimated Aid-To-Construct, then the Customer shall pay to the Utility the difference between the Actual Aid-To-Construct and the Revised Aid-To-Construct within five (5) Business Days; and

(b) if the Revised Estimated Aid-To-Construct exceeds the Actual Aid-To-Construct then the Utility shall pay to the Customer the difference between the Actual Aid-To-Construct and the Revised Aid-To-Construct within five (5) Business Days.

3.14 If the Customer does not agree with the Actual Capital Cost and Actual Aid-To-Construct, the Parties shall negotiate in good faith for a period of 20 Business days to establish an Actual Capital Cost. If the Parties are unable to agree after such negotiations then either party may refer the matter to the OEB for resolution. 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 the Utility to establish gas distribution service for the Customer, 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 agreement required to provide gas distribution service to the Customer;

(b) Consultant costs will include the reasonable cost of consultants incurred by the Utility to provide gas distribution service to the Customer, including the reasonable cost to complete the economic analysis to determine the Initial Estimated Aid-to-Construct, the Revised Estimated Aid-to-Construct and the Actual Aid-to-Construct; to carry out title searches to identify adjacent landowners and others with interests in adjacent lands that may be impacted by the Utility Connection Facilities; and the estimated cost of a Surveyor in the amount of $52,400;

(c) The Capital Cost will include the cost of services provided to the Utility by Aecon and any sub-contractors to Aecon, to complete the design of the Utility Connection Facilities, obtain all permits and approvals, , prepare and complete the request for quotation documents for the Construction Agreement and all other competitive processes for services and materials, and the cost estimated by Aecon to be in the range of $30,000 to $50,000 for the third party borehole drilling sub-contractor for the completion of boreholes used in the preparation of the Tender Package;

(d) Utility costs shall include the reasonable cost of interest during construction calculated in accordance with the OEB approved methodology and Overhead related to the Pipeline Work. Internal utility costs will include reasonable administrative and supervisory costs; and technician and field personnel required for the testing and commissioning of the Utility Connection Facilities.

(e) The reasonable costs of non-destructive testing of the welds and third party inspection of the Construction.

(f) The reasonable cost of the completion of as-built drawings for the Utility Connection Facilities.

(g) All consulting and third party costs include reasonable disbursements made by the third party or consultant unless such disbursements are included in a fixed fee quotation.

3.15 The Utility shall calculate and provide a partial refund of the Actual Aid-To-Construct, using the same methodology used to calculate the Actual Aid-To-Construct, if available capacity is assigned to another customer within seven years of the date on which the Utility Connection Facilities come into service, provided that the Utility is permitted by the Board to obtain any financial contribution that might be required from the subsequent customer to cover the amount of the refund. The calculation will be carried out once a year, based on the aggregate customer additions for the year. The calculation for the refund will be based on the same inputs used for the original calculation of the Actual Aid-To-Construct, except for the Capital Cost of the facilities which shall be prorated on the basis of the total capacity of the Utility Connection Facilities minus the capacity assigned to any subsequent customers.

ARTICLE IV – CONSTRUCTION

4.1 Prior to awarding of the Construction Contract, the Customer shall enter into a seven year gas delivery agreement as mutually agreed to by the Parties with a minimum annual volume of 33,416,618 m^3 and a firm contract demand of 108,188 m^3/day (Gas Delivery Agreement).

4.2 The timely completion of the Utility Connection Facilities is in the interest of the Parties. As part of the Construction Agreement, the Utility shall require the contractor to post a performance bond, including a liquidated damages provision, or other performance assurance measures acceptable to the Customer acting in a reasonable manner.

4.3 Prior to the termination of this Agreement, the Utility shall provide the Customer with weekly updates in writing as to costs incurred, costs committed to but not yet incurred and projected costs associated with the Pipeline Work. The Utility shall provide all supporting documentation (quotations, estimates, invoices, bills of lading, receipts, timesheets, etc.) for all costs incurred. As part of the updates, the Utility shall provide the Customer with a description of upcoming work; the anticipated procurement method and a recommended course of action. The Customer and the Utility shall discuss significant upcoming expenditures prior to committing to such expenditures and shall work co-operatively to meet all timelines and to minimize the costs in the circumstances. The Customer shall consent to such significant expenditures prior to the Utility committing to such expenditures, such consent to be given in a timely manner and not to be unreasonably withheld.

4.4 The Parties acknowledge that any change in the scope of the Pipeline Work may result in a change to the Capital Cost, the Aid-to-Construct, the Customer Letter of Credit and the Construction schedule. A change in scope of the Pipeline Work may come about as a result of any of the following:

(a) a Customer-initiated scope change;

(b) a requirement or condition imposed by a Governmental Authority, including without limitation, the OEB;

(c) unplanned delays on the part of the Customer or Subcontractor; or

(d) an event of Force Majeure (as determined in accordance with Article VI).

4.5 In the event of a change in the scope of the Pipeline Work, as contemplated in Section 4.4, in excess of $25,000, the Utility shall inform the Customer immediately of the nature of the change and the corresponding impact on the cost of the Pipeline Works. In the event such change will cause an increase in the Actual Capital Cost, the Utility shall obtain the Customer's consent to such increase prior to incurring such cost, such consent not to be unreasonably withheld and to be provided within 3 Business Days of receiving the information. In the event the Customer's consent has not been given within 3 Business Days, the Customer shall be deemed to have given consent to complete such work.

4.6 The Utility shall use all reasonable efforts to have the Pipeline Work (as described in Schedule A) completed by November 1, 2007 provided that:

(a) the Customer executes and returns this Agreement to the Utility by no later than February 1, 2007 (the "Execution Date");

(b) the Pipeline Work is completed in accordance with Schedule A of this Agreement;

(c) the Customer is in compliance with its obligations under this Agreement;

(d) there are no delays associated with third parties, including but not limited to Union Gas Limited, the Utility's lender and any companies selected to carry out Construction;

(e) the Utility is granted Leave-to-Construct by March 1, 2007; and,

(f) the Utility does not have to use its employees, agents and contractors performing the Pipeline Work elsewhere on its system due to an emergency, or an event of Force Majeure. For the purposes of this paragraph, an emergency means a line-break, leak, fire or similar event requiring an immediate response from the Utility.

4.7 As soon as the Utility becomes aware of any delay that may prevent the Utility from achieving the November 1, 2007 deadline, the Utility shall provide the Customer with notice in writing of such potential delay, the length of the anticipated delay and the reasons for such potential delay.

ARTICLE V – DEFAULT AND REMEDIES

5.1 Each of the following will constitute an Event of Default by the Customer ("Customer Event of Default"):

(a) The Customer fails to make any payment when due, if such failure is not remedied within ten (10) Business Days after written notice of such failure from the Utility.

(b) The Customer fails to deliver or maintain the Customer Letter of Credit or the Delivery Letter of Credit when due.

(c) The Customer fails to perform any material covenant or obligation set forth in this Agreement if such failure is not remedied within fifteen (15) Business Days after written notice of such failure from the Utility.

(d) Any representation made by the Customer in this Agreement is not true or correct in any material respect when made and is not made true or correct in all material respects within thirty (30) Business Days after receipt by the Customer of written notice of such fact from the Utility.

(e) An effective resolution is passed or documents are filed in an office of public record in respect of, or a judgment or order is issued by a court of competent jurisdiction ordering, the dissolution, termination of existence, liquidation or winding up of the Customer, unless such filed documents are immediately revoked or otherwise rendered inapplicable, or unless there has been a permitted and valid assignment of this Agreement by the Customer under this Agreement to a person which is not dissolving, terminating its existence, liquidating or winding up and such person has assumed all of the Customer's obligations under this Agreement.

(f) The Customer makes an assignment for the benefit of its creditors generally under any Insolvency Legislation, or consents to the appointment of a receiver, manager, receiver-manager, monitor, trustee in bankruptcy, or liquidator for all or part of its property or files a petition or proposal to declare bankruptcy or to reorganize pursuant to the provision of any Insolvency Legislation, or otherwise seeks the protection of Insolvency Legislation regardless of whether a proposal or plan is proposed.

(g) A receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy of the Customer or of any of the Customer's property is appointed by a Governmental Authority or pursuant to the terms of a debenture or a similar instrument, and such receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy is not discharged or such appointment is not revoked or withdrawn within thirty (30) days of the appointment.

(h) By decree, judgment or order of a Governmental Authority, the Customer is adjudicated bankrupt or insolvent or any substantial part of the Customer's property is sequestered, and such decree continues undischarged and unstayed for a period of thirty (30) days after the entry thereof.

(i) A petition, proceeding or filing is made against the Customer seeking to have the Customer declared bankrupt or insolvent, or seeking adjustment or composition of any of their respective debts pursuant to the provisions of any Insolvency Legislation, and such petition, proceeding or filing is not dismissed or withdrawn within thirty (30) days.

5.2 Each of the following will constitute an Event of Default by the Utility ("Utility Event of Default"):

(a) The Utility fails to perform any material covenant or obligation set forth in this Agreement if such failure is not remedied within fifteen (15) Business Days after written notice of such failure from the Customer.

(b) Any representation made by the Utility in this Agreement is not true or correct in any material respect when made and is not made true or correct in all material respects within thirty (30) Business Days after receipt by the Utility of written notice of such fact from the Customer.

(c) An effective resolution is passed or documents are filed in an office of public record in respect of, or a judgment or order is issued by a court of competent jurisdiction ordering, the dissolution, termination of existence, liquidation or winding up of the Utility, unless such filed documents are immediately revoked or otherwise rendered inapplicable, or unless there has been a permitted and valid assignment of this Agreement by the Utility under this Agreement to a person which is not dissolving, terminating its existence, liquidating or winding up and such person has assumed all of the Utility's obligations under this Agreement.

(d) The Utility makes an assignment for the benefit of its creditors generally under any Insolvency Legislation, or consents to the appointment of a receiver, manager, receiver-manager, monitor, trustee in bankruptcy, or liquidator for all or part of its property or files a petition or proposal to declare bankruptcy or to reorganize pursuant to the provision of any Insolvency Legislation, or otherwise seeks the protection of Insolvency Legislation regardless of whether a proposal or plan is proposed.

(e) A receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy of the Utility or of any of the Utility's property is appointed by a Governmental Authority or pursuant to the terms of a debenture or a similar instrument, and such receiver, manager, receiver-manager, liquidator, monitor or trustee in bankruptcy is not discharged or such appointment is not revoked or withdrawn within thirty (30) days of the appointment.

(f) By decree, judgment or order of a Governmental Authority, the Utility is adjudicated bankrupt or insolvent or any substantial part of the Utility's property is sequestered, and such decree continues undischarged and unstayed for a period of thirty (30) days after the entry thereof.

(g) A petition, proceeding or filing is made against the Utility seeking to have the Utility declared bankrupt or insolvent, or seeking adjustment or composition of any of their respective debts pursuant to the provisions of any Insolvency Legislation, or such petition, proceeding or filing is not dismissed or withdrawn within thirty (30) days.

(h) A failure to maintain in good standing any franchise agreement or any other approval, permit or license from any Governmental Authority required for the construction and operation of the Pipeline Works and the supply of natural gas to the Customer Facility.

ARTICLE VI – FORCE MAJEURE

6.1 In the event that either the Customer or the Utility is rendered unable, in whole or in part, by Force Majeure, to perform or comply with any obligation or condition of this Agreement, then the obligations (other than the obligations to make payment of money then due and to provide or maintain any letter of credit) of both parties so far as they are directly related to and affected by such Force Majeure, shall be suspended during the continuance of the Force Majeure.

6.2 The party claiming Force Majeure shall give notice in writing, with full particulars, to the other party as soon as possible after the occurrence of Force Majeure.

6.3 The party claiming Force Majeure shall also give notice to the other party as soon as possible after the Force Majeure is remedied in whole or part.

6.4 Force Majeure means:

(a) Acts of God, landslides, lightning, earthquakes, fires, storms, floods, washouts, explosions, breakage or accident to its machinery or equipment or lines of pipe;

(b) freezing or failure of wells or lines of pipe; curtailment of firm transportation or firm storage by other natural gas service providers;

(c) strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections, civil disturbance, acts of terrorism, wars, arrests or restraint of governments and people;

(d) any laws, orders, rules, regulations, acts of any government body or authority, civil or military;

(e) any act or omission by parties not controlled by the party claiming Force Majeure; and

(f) any other similar causes not within the control of the party claiming Force Majeure

which by the exercise of due diligence such party is unable to prevent or overcome. The party claiming Force Majeure shall make reasonable efforts to avoid, or correct the Force Majeure and to remedy the Force Majeure once it has occurred in order to resume performance.

6.5 Neither party shall be entitled to claim Force Majeure if any of the following circumstances prevail:

(a) the failure resulting in Force Majeure was caused by the negligence of the party claiming suspension;

(b) the failure was caused by the party claiming suspension where such party failed to remedy the condition by making all reasonable efforts (short of litigation, if such remedy would require litigation);

(c) the party claiming suspension failed to resume the performance of such conditions or obligations with reasonable dispatch;

(d) the failure was caused by lack of funds; and

(e) the party claiming suspension did not give to the other party the required notice as soon as possible after determining or within a period within which it should have determined, acting reasonably, that the occurrence was in the nature of Force Majeure and would affect its ability to observe or perform any of its conditions or obligations under the Agreement.

ARTICLE VII – SECURITY AND PERFORMANCE ASSURANCE

7.1 Prior to the Utility ordering the pipe and the stations, the Customer shall provide to the Utility an irrevocable letter or letters of credit ("Customer Letter of Credit") in an amount equal to the quoted cost of the pipe and the stations minus any payments made by the Customer to the Utility in respect of the pipe and the stations. The Customer shall be entitled to reduce the Customer Letter of Credit by the amount of any subsequent payments by the Customer to the Utility in respect of the pipe and the stations, upon making such payments. The Utility shall be entitled to draw upon the Customer Letter of Credit in the following circumstances:

(a) Subject to (b), if the Customer fails to make a payment of the Aid-to-Construct in accordance with Article III, such draw not to exceed the amount owed by the Customer to the Utility.

(b) Notwithstanding (a) the Utility shall not be entitled to draw upon the Customer Letter of Credit within any cure periods established in Article V, in which the Customer may make payment to the Utility.

7.2 The Utility shall return the Customer Letter of Credit upon receipt of any payment required from the Customer in accordance with section 3.4 and delivery of the Delivery Letter of Credit required under section 7.3.

7.3 Prior to the award of the Construction Agreement by the Utility, the Customer shall provide to the Utility an irrevocable letter of credit ("Delivery Letter of Credit") in an amount equal to the difference between the Revised Estimated Capital Cost and the Revised Estimated Aid-to-Construct.

7.4 The Utility shall be entitled to draw upon the Delivery Letter of Credit if:

(a) The Customer terminates this Agreement prior to the In-Service Date and fails to pay any amount owing to the Utility within 30 Business Days of receiving the invoice for monies owed for actual reasonable costs incurred prior to Termination; or

(b) The Customer terminates this Agreement and the Gas Delivery Contract after the In-Service Date but prior to the seventh anniversary of the Commencement Date under the Gas Delivery Contract;

(c) For any year, the Customer fails to take receipt of the Minimum Annual Volume under the Gas Delivery Contract and the Customer fails to pay the invoice for such failure to take the Minimum Annual Volume within 15 days of receiving such invoice;

(d) For reasons other than Force Majeure, the Customer ceases taking service for a period of 30 days during the term of the Gas Delivery Contract or at any time after that where service has continued past the end of the term of the Gas Delivery Contract;

(e) the Delivery Letter of Credit will not be maintained and the Customer fails to provide a substitute acceptable to the Utility and its lender; or

(f) The Customer commits a Customer Event of Default listed in 5.1 (e), (f), (g), (h) and (i).

(g) The Customer fails to restore the balance of the Delivery Letter of Credit as required by 7.5.

7.5 The Customer shall maintain the Delivery Letter of Credit for as long as the Customer continues to receive service from the Utility. In the event that the Utility draws on the Delivery Letter of Credit pursuant to 7.4(c), the Customer shall restore the Delivery Letter of Credit to the balance that existed immediately prior to the draw, within 10 Business Days from the date of the draw.

7.6 Subject to section 7.7, the Customer shall be entitled to reduce the amount of the Delivery Letter of Credit on each anniversary of the commencement of deliveries under the Gas Delivery Agreement to an amount equal to the net book value of the Utility Connection Facilities allocated to the Customer at the time, as determined by the Utility in accordance with OEB-approved methodology.

7.7 Any letter of credit shall be in a form acceptable to the Utility and its lender. The Utility shall have its lender provide a draft form of letter of credit for review and comment by the Customer's lender.

7.8 The costs and expenses of establishing, renewing, substituting, cancelling, increasing and reducing the amount of (as the case may be) any letter of credit required under this Agreement shall be borne by the Customer.

7.9 The Utility shall return any letter of credit held by the Utility to the Customer, if the Customer is substituting a letter of credit with another letter of credit or such other financial assurance, where that substitute is acceptable to the Utility and its lender.

ARTICLE VIII – TERMINATION

8.1 This Agreement terminates upon the placing into service of the Utility Connection Facilities and the Union Gas Connection Facilities and the commencement of the delivery of natural gas to the Customer Facility. All payment obligations and all obligations in relation to the Customer Letter of Credit and Delivery Letter of Credit shall survive termination of this Agreement until they are fulfilled.

8.2 In the event that the Utility is unable to secure all necessary permits, approvals, licenses certificates necessary to complete the Pipeline Work and supply natural gas to the Customer Facility, or obtains such permits, approvals, licenses or certificates on terms and conditions that are unacceptable to the Customer, acting in a commercially reasonable manner, then the Customer has the option to terminate this Agreement. The Customer shall, however, be responsible for all actual or committed to costs incurred by the Utility and Union Gas Limited up to and including the date of termination.

8.3 The Utility may terminate this Agreement if a Customer Event of Default has occurred and the Utility has given notice to the Customer of such Customer Event of Default and such default is not remedied within the applicable cure period upon receiving such notice of default. Termination pursuant to this section shall not be permitted where such default has been submitted to a dispute resolution process under Article IX.

8.4 Subject to Section 8.5, in the event the Revised Estimated Aid-To-Construct has been paid, in full or in part, by the Customer to the Utility and the Agreement is terminated prior to completion of the Pipeline Work, then the Utility shall return to the Customer any amount of the Revised Estimated Aid-To-Construct paid by the Customer that is in excess of the actual reasonable cost incurred by the Utility up to and including the date of termination. In the event the actual reasonable cost incurred by the Utility exceed the amount of the Revised Estimated Aid-To-Construct, the Customer shall pay that amount, upon receipt of which the Utility shall forthwith return the Delivery Letter of Credit.

8.5 In the event Utility invokes Force Majeure and the event of Force Majeure or the aggregate duration of all such Utility events of Force Majeure exceeds 60 days in any 12 consecutive month period, then the Customer shall have the right to terminate this Agreement upon fifteen (15) Business Days written notice. Upon termination of this Agreement pursuant to this section, the Utility shall return all security and financial assurance provided by Customer, and an amount, if any, equal to any Aid-To-Construct paid by the Customer to the Utility less the Utility's reasonable costs incurred prior to the event of Force Majeure.

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 the matter to the OEB for resolution.

ARTICLE X – INDEMNIFICATION

10.1 The Utility agrees to indemnify, defend, and hold harmless the Customer in respect of all actions, causes of action, suits, proceedings, claims, demands, losses, damages, penalties, fines, costs, obligations and liabilities ("Damages") arising out of the construction, installation, testing, commissioning and operation of the Utility Connection Facilities, other than any Damages caused by the negligence or wilful misconduct of the Customer.

10.2 The Customer agrees to indemnify, defend and hold harmless the Utility in respect of all Damages arising out of the construction, installation, testing, commissioning and operation of the Utility Connection Facilities caused by the negligence or wilful misconduct of the Customer.

ARTICLE XI – GENERAL

11.1 Any written notice required by this Agreement shall be deemed properly given only if either mailed or delivered to:

(a) To the Utility:

Natural Resource Gas Limited
P.O. Box 307
39 Beech Street East
Aylmer, Ontario N5H 2S1

Tel: (519) 773-5321
Fax: (519) 773-5335

Attention: Steve Millar, General Manager
c.c. Mark Bristoll, President

(b) To the Customer:

Integrated Grain Processors Co-operative Inc.
701 Powerline Road
Brantford, Ontario N3T 5L8

Tel: (519) 752-0447
Fax: (519) 752-1887

Attention: Chair

A faxed notice will be deemed to be received on the date of the fax if received before 4 p.m. or on the next Business Day if received after 4 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

11.2 This Agreement:

(a) constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of 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 disputes arising out of this Agreement;

(c) may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement; and

(d) shall not be assigned without the prior written consent of the other party, such consent not to be unreasonably withheld. For greater certainty an assignment by way of security to the Customer's lenders shall be considered reasonable.

11.3 No modification of or amendment to this Agreement will be valid or binding unless set forth in writing and duly executed by both of the parties hereto and no waiver of any breach of any term or provision of this Agreement will be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided, will be limited to the specific breach waived.

11.4 If any provision of this Agreement is determined to be invalid or unenforceable or in breach of any Applicable Law in whole or in part, such invalidity or unenforceability will attach only to such provision or part thereof which provision or part shall be severed from the Agreement and the remaining part of such provision and all other provisions hereof will continue in full force and effect.

11.5 Notwithstanding the termination or expiration of this Agreement:

(a) Section 3.15 shall survive for the period of time provided in which a refund is to be calculated.

(b) The obligation to make any payment shall survive until all such payments are determined and paid.

(c) Article 7 shall survive until the Utility no longer requires financial assurance from the Customer.

(d) Article IX shall survive until the final resolution, including all appeals, of any dispute arising out of this Agreement.

11.6 Each Party shall from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

11.7 This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the Parties hereto.

11.8 Time is of the essence in the performance of the Parties' respective obligations under this Agreement.

11.9 Any reference to funds is a reference to Canadian currency.

11.10 This Agreement is subject to the consent of the Customer's Lenders. The Customer agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Customer. The Customer shall waive this condition in writing.

11.11 This Agreement is subject to the consent of the Utility's Lenders. The Utility agrees to use reasonable efforts to secure such consent in a timely manner. This paragraph is entirely for the benefit of the Utility. The Utility shall waive this condition in writing.

11.12 In the event of a change of law affecting any of the rights or obligations of one Party to the other Party, the Utility shall continue to deliver gas and the Customer shall continue to pay for the delivery of gas as if the change had not occurred unless prohibited by law. In such event the Parties shall negotiate in good faith to preserve the original intent of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

NATURAL RESOURCE GAS LIMITED

Per: Mark Bristoll
Title: President

I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

Per: Tom Cox
Title:

I have authority to bind the corporation.

Per: Brent McBlain
Title:

I have authority to bind the corporation.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

NATURAL RESOURCE GAS LIMITED

Per: Mark Bristoll
Title: President

I have authority to bind the corporation.

INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC.

Per: Tom Cox
Title:

I have authority to bind the corporation.

Per: Brent McBlain
Title:

I have authority to bind the corporation.

Schedule A - Pipeline Work

In carrying out the Pipeline Work (as depicted in the figure attached as Schedule B to this Agreement), the Utility or a subcontractor to the Utility will need to complete the following:

Pipeline Work Planning

Utility Connection Facilities

1. The Utility shall design, construct, install, commission and operate the Utility Connection Facilities in accordance with all Applicable Laws and good utility practice.

2. The Utility shall be responsible for making applications to all Governmental Authorities for all permits, approvals, licenses and certificates necessary to undertake and complete the Utility Connection Facilities, including without limiting the foregoing, the Leave-to-Construct from the OEB. The Utility shall be responsible for maintaining all such permits, approvals, licenses in good standing.

3. The Utility shall only contract with suppliers and contractors competent to perform their tasks and shall undertake to secure competitive bids from competent suppliers and contractors for the Utility Connection Facilities.

4. The Utility and the Customer shall agree to a suitable location at the Customer Facility for the Customer Meter Facility.

5. The Utility shall coordinate the design, construction, testing and operation of the Utility Connection Facilities with Union Gas Limited such that Union Gas Limited will be able to supply the Utility with sufficient quantities of natural gas to meet the Customer's requirements by the In-Service Date.

6. The Utility shall furnish the Customer with a complete set of engineered stamped drawings of the Utility Connection Facilities before tendering for the Construction Agreement. The engineer shall be qualified to practice engineering in Ontario.

7. The Utility shall provide a flanged connection at the outlet of the Customer Meter Facility to which the Customer may connect the house-piping for the Customer Facility. In the event the Customer installs the house-piping with flanged connection prior to the Utility, the Utility shall be responsible for completing the connections. The flanged connection shall be adequately protected to prevent the entry of dirt, water or other extraneous materials from entering the Customer Meter Facility or the house-piping.

8. The Utility shall ensure the Customer Meter Facility is properly insulated from the Customer Facility.

9. The Utility shall furnish the Customer the required communications specifications for the Customer Meter Facility with the stamped drawings.

Access To Customer Facility

10. The Customer shall provide the Utility and its contractor with reasonable access to the Customer Facility to construct, install, test, commission and operate the Customer Meter Facility.

11. The Utility shall ensure that all employees of the Utility or its contractor obey all safety requirements of the Customer while on the Customer Facility.

Pipeline Work Testing and Commissioning

12. The Utility shall coordinate hydrotesting or any other testing, including non-destructive testing of welds, of the Utility Connection Facilities with the Customer and the Utility shall not interfere with the construction, installation, testing or commissioning of the Customer Facility.

13. The Utility shall ensure that the Utility Connection Facility is completely dewatered. Dewatering shall not occur on the Customer Facility.

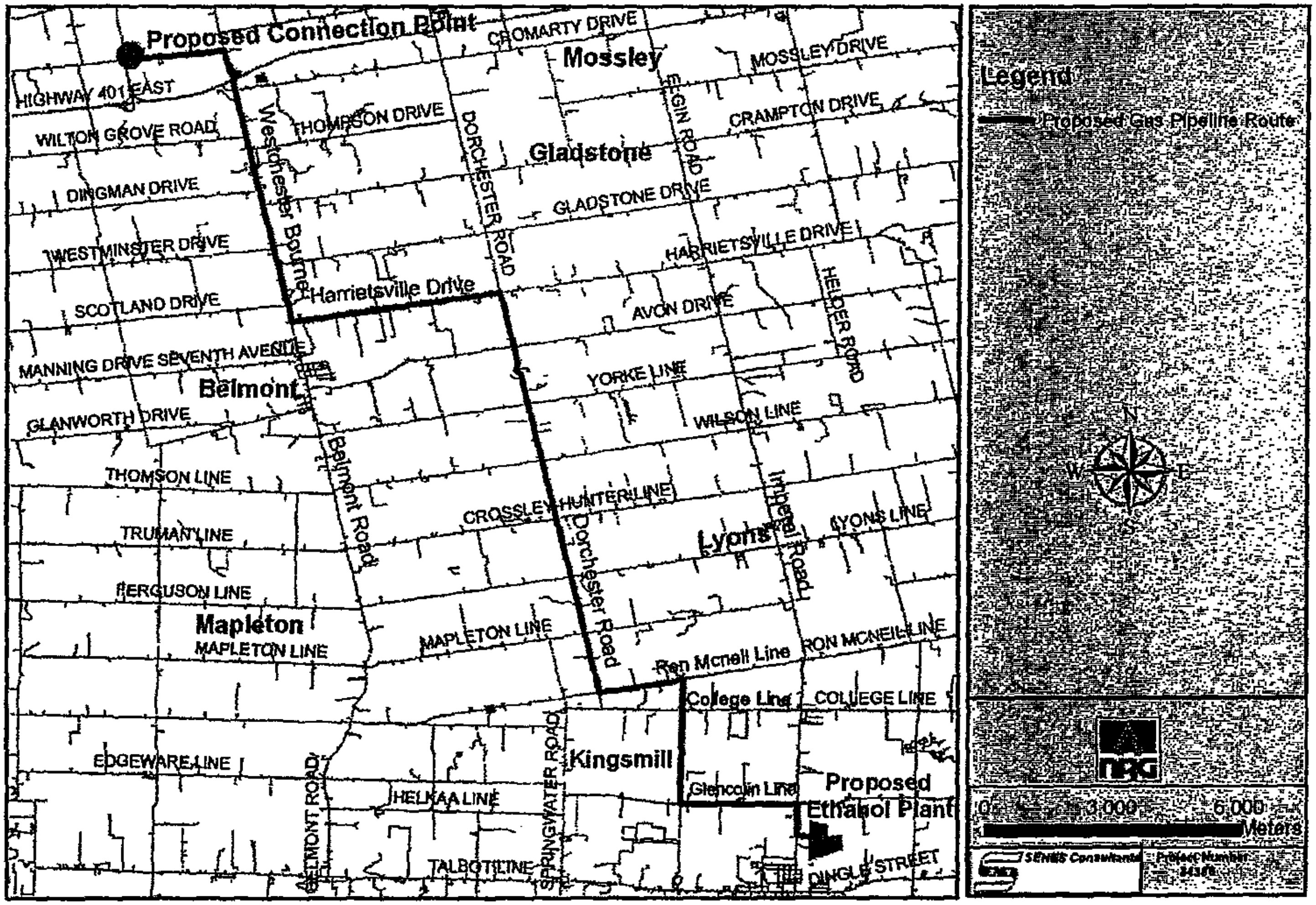
Union Gas Connection Facilities

14. The Utility shall coordinate the construction of the Utility Connection Facilities with Union Gas Ltd. to facilitate the completion of the Union Gas Connection Facilities by or before November 1, 2007.

SCHEDULE B - PROJECT MAP

[To be inserted]

Proposed NRG Ltd. Gas Pipeline Route



RBC Royal Bank

ORIGINAL

INT'L TRADE CENTRE - ONTARIO
180 WELLINGTON ST WEST
4TH FLOOR
TORONTO, ONTARIO, M5J 1J1
CANADA

AMENDMENT TO IRREVOCABLE STANDBY LETTER OF CREDIT

DATE: APRIL 25, 2014

OUR REFERENCE NO.: P436645T04117

CURRENCY AND AMOUNT: CAD 5,214,173.00

BENEFICIARY:
NATURAL RESOURCE GAS LIMITED
39 BEECH ST.
AYLMER, ON N5H 2S1

APPLICANT:
IGPC ETHANOL INC.
89 PROGRESS DRIVE, PO BOX 205
AYLMER ON
N5H 2R9

KINDLY NOTE THAT THE ABOVE MENTIONED IRREVOCABLE STANDBY LETTER OF CREDIT IS AMENDED AS FOLLOWS:

THE AMOUNT OF THIS LETTER OF CREDIT SHALL BE REDUCED BY CAD.1,722,442.00 TO A NEW TOTAL AMOUNT OF CAD.3,491,731.00 (THREE MILLION FOUR HUNDRED NINETY ONE THOUSAND SEVEN HUNDRED THIRTY ONE AND 00/100'S CANADIAN DOLLARS).

PLEASE CONFIRM YOUR ACCEPTANCE OF THIS AMENDMENT BY SIGNING BELOW AND FAX BACK TO US THE COMPLETE AMENDMENT PAGES 1 AND 2 AT 1-800-450-7774.

RBC Royal Bank

ORIGINAL

AUTHORIZED SIGNATORY OF
NATURAL RESOURCE GAS LIMITED

THIS AMENDMENT IS TO BE CONSIDERED AS PART OF THE ABOVE IRREVOCABLE STANDBY LETTER OF CREDIT AND MUST BE ATTACHED THERETO.

ALL OTHER TERMS AND CONDITIONS REMAIN UNCHANGED.

ROYAL BANK OF CANADA

B. KING RAMDIN

AUTHORIZED SIGNATURE

Sharon Zhu

AUTHORIZED SIGNATURE

RBC Royal Bank

COPY

INT'L TRADE CENTRE - ONTARIO
180 WELLINGTON ST WEST
4TH FLOOR
TORONTO, ONTARIO, M5J 1J1
CANADA

DATE OF ISSUE: NOVEMBER 4, 2013

OUR REFERENCE NUMBER:
P436645T04117

DATE OF EXPIRY: NOVEMBER 30, 2014
PLACE OF EXPIRY: TORONTO, ONTARIO

BENEFICIARY:
NATURAL RESOURCE GAS LIMITED
39 BEECH ST.
AYLMER, ON N5H 2S1

APPLICANT:
IGPC ETHANOL INC.
89 PROGRESS DRIVE, PO BOX 205
AYLMER ON
N5H 2R9

AMOUNT: CAD 5,214,173.00
FIVE MILLION TWO HUNDRED FOURTEEN THOUSAND ONE HUNDRED SEVENTY THREE AND 00/100'S CANADIAN DOLLARS

IRREVOCABLE STANDBY LETTER OF CREDIT NO. P436645T04117

PURSUANT TO THE REQUEST OF THE APPLICANT, WE, ROYAL BANK OF CANADA INTERNATIONAL TRADE CENTRE-ONTARIO, 4TH FLOOR, 180 WELLINGTON STREET WEST, TORONTO, ONTARIO, CANADA, M5J 1J1 (THE "BANK"), HEREBY ESTABLISH IN FAVOR OF THE BENEFICIARY AND GIVE THE BENEFICIARY THIS IRREVOCABLE STANDBY LETTER OF CREDIT NO. P436645T04117 (THIS "LETTER OF CREDIT") IN THE AMOUNT OF CAD.5,214,173.00 (FIVE MILLION TWO HUNDRED FOURTEEN THOUSAND ONE HUNDRED SEVENTY THREE AND 00/100'S CANADIAN DOLLARS ONLY).

WE ARE INFORMED BY THE APPLICANT THAT THIS LETTER OF CREDIT IS ISSUED PURSUANT TO SECTION 7.3 OF THAT CERTAIN PIPELINE COST RECOVERY AGREEMENT DATED AS OF

RBC Royal Bank

COPY

JANUARY 31, 2007 BETWEEN INTEGRATED GRAIN PROCESSORS CO-OPERATIVE INC. ("IGPC") AND THE BENEFICIARY, AS ASSIGNED TO THE APPLICANT PURSUANT TO AN ASSIGNMENT AGREEMENT DATED AS OF MARCH 30, 2007 BETWEEN IGPC, THE APPLICANT AND THE BENEFICIARY.

THE BENEFICIARY MAY DRAW ON THIS LETTER OF CREDIT AT ANY TIME AND FROM TIME TO TIME PRIOR TO THE EXPIRY OF THIS LETTER OF CREDIT UPON WRITTEN DEMAND IN THE FORM OF SCHEDULE 2 ATTACHED (THE "DEMAND") COMPLETED AND PURPORTEDLY SIGNED BY AN AUTHORIZED OFFICER OF THE BENEFICIARY ACCOMPANIED BY THE ORIGINAL OF THIS LETTER OF CREDIT AND ALL AMENDMENTS HERETO (IF ANY). WE SHALL PAY TO THE BENEFICIARY IN ACCORDANCE WITH THE DEMAND THE LESSER OF (I) THE AMOUNT OF THE DEMAND, AND (II) THE MAXIMUM LIABILITY (AS DEFINED IN SCHEDULE 1 ATTACHED). WE SHALL HONOR A DEMAND WITHN 3 (THREE) BUSINESS DAYS (AS DEFINED IN SCHEDULE 1 ATTACHED) OF RECEIPT OF THE DEMAND, WITHOUT INQUIRING WHETHER THE BENEFICIARY HAS THE RIGHT AS BETWEEN THE BENEFICIARY AND THE APPLICANT TO MAKE SUCH DEMAND, AND WITHOUT RECOGNIZING ANY CLAIM OF THE APPLICANT. WE SHALL ENDORSE THE ORIGINAL OF THIS LETTER OF CREDIT WITH THE AMOUNT OF THE DEMAND UPON OUR PAYMENT AND RETURN THE ORIGINAL OF THIS LETTER OF CREDIT TO THE BENEFICIARY.

THIS LETTER OF CREDIT WILL CONTINUE FROM 1 DECEMBER, 2013 AND WILL EXPIRE AT OUR COUNTERS ON 30 NOVEMBER 2014 AND THE BENEFICIARY MAY CALL FOR PAYMENT OF THE FULL AMOUNT OUTSTANDING UNDER THIS LETTER OF CREDIT AT ANY TIME UP TO THE CLOSE OF BUSINESS ON THAT DATE OR ANY FUTURE EXPIRY DATE. THIS LETTER OF CREDIT SHALL BE DEEMED TO BE AUTOMATICALLY EXTENDED FOR ONE YEAR FROM THE PRESENT OR ANY FUTURE EXPIRATION DATE HEREOF, UNLESS AT LEAST THIRTY (30) DAYS PRIOR TO ANY SUCH DATE, WE SHALL NOTIFY THE BENEFICIARY IN WRITING BY REGISTERED MAIL OR COURIER SENT TO: 39 BEECH ST. AYLMER, ON., N5H 2S1 OR SUCH OTHER ADDRESS AS THE BENEFICIARY MAY DESIGNATE IN WRITING, THAT WE ELECT NOT TO CONSIDER THIS LETTER OF CREDIT EXTENDED FOR ANY SUCH ADDITIONAL PERIOD. UPON AND AT ANY TIME FOLLOWING THE BENEFICIARY'S RECEIPT OF SUCH NOTICE, BUT PRIOR TO THE EXPIRY OF THIS LETTER OF CREDIT, THE BENEFICIARY MAY DRAW HEREUNDER.

PARTIAL OR MULTIPLE DRAWINGS ARE PERMITTED.

THE AMOUNT OF THIS LETTER OF CREDIT MAY BE REDUCED AT ANY TIME BY NOTICE TO THE BANK SIGNED BY THE BENEFICIARY ACCOMPANIED BY THE ORIGINAL OF THIS LETTER OF CREDIT AND ALL AMENDMENTS HERETO (IF ANY) (EACH A "REDUCTION"). WE SHALL ENDORSE THE ORIGINAL OF THIS LETTER OF CREDIT WITH THE AMOUNT OF THE REDUCTION AND RETURN THE ORIGINAL OF THIS LETTER OF CREDIT TO THE BENEFICIAIRY.

THIS LETTER OF CREDIT IS NOT TRANSFERABLE.

RBC Royal Bank

COPY

THE BENEFICIARY MAY ASSIGN THE PROCEEDS OF THIS LETTER OF CREDIT TO ANY LENDER TO THE BENEFICIARY FROM TIME TO TIME, PROVIDED, HOWEVER, THAT WE ARE NOT OBLIGED TO GIVE EFFECT TO SUCH ASSIGNMENT EXCEPT TO THE EXTENT THAT WE HAVE ACKNOWLEDGED SUCH ASSIGNMENT IN ACCORDANCE WITH UCP 600 (AS DEFINED BELOW).

ALL PAYMENTS TO BE MADE BY US UNDER THIS LETTER OF CREDIT SHALL BE MADE WITHOUT ANY DEDUCTION OF TAXES, LEVIES, CHARGES, FEES, DEDUCTIONS OR WITHHOLDINGS OF ANY NATURE AND SHALL BE MADE WITHOUT ANY SET-OFF OR COUNTERCLAIM.

ALL AMENDMENTS UNDER THIS LETTER OF CREDIT WILL BE EFFECTIVE ONLY ON THE BANK'S RECEIPT OF THE WRITTEN ACCEPTANCE OF SUCH AMENDMENT BY THE BENEFICIARY.

THIS LETTER OF CREDIT IS SUBJECT TO THE UNIFORM CUSTOMS AND PRACTICE FOR DOCUMENTARY CREDITS, 2007 REVISION, INTERNATIONAL CHAMBER OF COMMERCE, PARIS, FRANCE, PUBLICATION NO. 600 (THE "UCP 600"), EXCEPT TO THE EXTENT THAT THE UCP 600 IS INCONSISTENT WITH AN EXPRESS TERM OF THIS LETTER OF CREDIT.

AS TO MATTERS NOT COVERED BY THE UCP 600, THIS LETTER OF CREDIT SHALL BE GOVERNED BY THE LAWS OF THE PROVINCE OF ONTARIO AND THE FEDERAL LAWS OF CANADA APPLICABLE THEREIN.

SCHEDULE 1 - DEFINITIONS

"BUSINESS DAY" MEANS A DAY (OTHER THAN A SATURDAY OR SUNDAY) ON WHICH BANKS ARE OPEN FOR GENERAL BUSINESS IN TORONTO, ONTARIO AND MONTREAL, QUEBEC.

"MAXIMUM LIABILITY" MEANS AT ANY TIME, THE UNDRAWN BALANCE OF THIS LETTER OF CREDIT CALCULATED AS FIVE MILLION TWO HUNDRED FOURTEEN THOUSAND ONE HUNDRED SEVENTY THREE CANADIAN DOLLARS (CAD5,214,173.00) LESS ANY REDUCTIONS AND LESS ANY DRAWINGS WHICH WE HAVE PAID UNDER THIS LETTER OF CREDIT.

RBC Royal Bank

COPY

SCHEDULE 2 (TO BE COMPLETED ON BENEFICIARY'S LETTERHEAD IN THE FOLLOWING FORMAT)

ROYAL BANK OF CANADA
INTERNATIONAL TRADE CENTRE-ONTARIO
180 WELLINGTON STREET WEST, 4TH FLOOR,
TORONTO, ONTARIO M5J 1J1

DEMAND FOR PAYMENT

DATE: ....

RE: IRREVOCABLE STANDBY LETTER OF CREDIT NUMBER .... ("LETTER OF CREDIT") DATED ......

AMOUNT: ....

WE REFER TO THE ABOVE REFERENCED LETTER OF CREDIT.

WE HEREBY DEMAND PAYMENT OF THE SUM OF .... CANADIAN DOLLARS UNDER THE ABOVE REFERENCED LETTER OF CREDIT.

WE REQUEST PAYMENT OF SUCH AMOUNT TO BE MADE BY ELECTRONIC TRANSFER TO THE FOLLOWING ACCOUNT:

BANK:
ADDRESS:
SORT CODE:
ACCOUNT NAME:
ACCOUNT NUMBER:

WE CONFIRM THAT PURSUANT TO THE PIPELINE COST RECOVERY AGREEMENT (AS DEFINED IN THE LETTER OF CREDIT) WE HAVE THE RIGHT TO DRAW SUCH AMOUNT.

YOURS FAITHFULLY,
BY: ......
AUTHORIZED SIGNATORY
NAME:
TITLE:

RBC Royal Bank

COPY

ROYAL BANK OF CANADA

B. KING RAMDIN

AUTHORIZED SIGNATURE

OTHER SIGNATURE

THIS DOCUMENT CONSISTS OF 5 PAGE(S).

M. PICACHE

Osler, Hoskin & Harcourt LLP
Box 50, 1 First Canadian Place
Toronto, Ontario, Canada M5X 1B8
416.362.2111 MAIN
416.862.6666 FACSIMILE

OSLER

Toronto

Montréal

Ottawa

Calgary

New York

May 8, 2014

Richard King
Direct Dial: 416.862.6626
rking@osler.com
Our Matter Number: 1144234

SENT BY EMAIL **sstoll@airdberlis.com**

Mr. Scott Stoll
Aird & Berlis LLP
Brookfield Place, 181 Bay Street
Suite 1800, Box 754
Toronto, ON M5J 2T9

Dear Scott:

NRG-IGPC (Amendment to Letter of Credit)

We acknowledge receipt of the Amendment to the Letter of Credit ("L/C") from Royal Bank, and have signed and returned it to the Royal Bank. We further acknowledge that: (a) the amended L/C is effective now; (b) the amended (reduced) amount of the L/C represents the amount of the undepreciated capital cost of the pipeline as at September 30, 2014; and (c) the next amendment will occur September 30, 2015.

Yours very truly,

Richard King
RK:rk

c: Jim Grey (IGPC Ethanol Inc.)
L. O'Meara (Natural Resource Gas)
T. Graat (Natural Resource Gas)

DEFERRAL ACCOUNT FOR NEW DSM FRAMEWORK

On March 26, 2014, the Minister of Energy issued a Directive to the Ontario Energy Board instructing the Board to take a variety of steps to promote electricity conservation and demand management ("CDM") and natural gas DSM (see Exhibit E, Tab 1, Schedule 2).

With respect to natural gas DSM, the Directive requires the Board to establish a DSM Framework for "natural gas distributors whose rates are regulated by the Board" (i.e., Union Gas, Enbridge and NRG). This DSM Framework would cover the six-year period from January 1, 2015 to December 31, 2020, and will require these natural gas distributors to coordinate and integrate their DSM Framework with the CDM programs of electricity distributors in the same service area. As a first step towards implementing the DSM Framework, on April 10, 2014, the Board gave notice (the "April 10 Notice") of a consultation process among natural gas distributors, electricity distributors and other interested parties pursuant to which the Board will develop a new DSM Framework (see Exhibit E, Tab 1, Schedule 3).

Historically, NRG has not been required to offer DSM programs to its customers. Many years ago, when DSM was initiated in Ontario's natural gas sector, NRG began to offer DSM programs. However, after a period of time during which there was very little up-take by NRG customers, the Board agreed that given the costs associated with offering such programs, in conjunction with the negligible uptake, NRG would not be required to offer DSM programs.

It appears that based on the Minister's Directive, the April 10 Notice from the Board, and the integration of gas and electricity conservation initiatives, that NRG will be required to offer DSM programs to its customers. Given that NRG does not currently offer these programs, NRG is proposing that a deferral account be created to track NRG's DSM costs over the next two years, for clearance at NRG's next cost-of-service rate case.

Order in Council
Décret

Ontario
Executive Council
Conseil exécutif

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

Sur la recommandation de la personne soussignée, le lieutenant-gouverneur, sur l'avis et avec le consentement du Conseil exécutif, décrète ce qui suit :

WHEREAS the government adopted a policy of putting conservation first in its 2013 Long-Term Energy Plan, *Achieving Balance.*

AND WHEREAS it is desirable to achieve reductions in electricity consumption and natural gas consumption to assist consumers in managing their energy bills, mitigating upward pressure on energy rates and reducing air pollutants, including greenhouse gas emissions, and to establish an updated electricity conservation policy framework ("Conservation First Framework") and a natural gas conservation policy framework.

AND WHEREAS the Minister of Energy intends to issue a direction to the Ontario Power Authority to require that it undertake activities to support the Conservation First Framework, including the funding of electricity distributor conservation and demand management programs.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.1 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources.

AND WHEREAS the Minister of Energy may, with the approval of the Lieutenant Governor in Council, issue directives under section 27.2 of the *Ontario Energy Board Act, 1998* in order to direct the Board to take steps to establish conservation and demand management targets to be met by electricity distributors and other licensees.

NOW THEREFORE the Directive attached hereto is approved and shall be and is effective as of the date hereof.

Recommended ______________
Minister of Energy

Concurred ______________
Chair of Cabinet

Approved and Ordered MAR 2 6 2014
Date

____
Lieutenant Governor

O.C./Décret 467/2014

MINISTER'S DIRECTIVE

TO: THE ONTARIO ENERGY BOARD

I, Bob Chiarelli, Minister of Energy, hereby direct the Ontario Energy Board (the "Board") pursuant to my authority under sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* (the "Act") to take the following steps to promote electricity conservation and demand management ("CDM") and natural gas demand side management ("DSM"):

1. The Board shall, in accordance with the requirements of this Directive and without holding a hearing, amend the licence of each licensed electricity distributor ("Distributor") to establish the following as the CDM target to be met by the Distributor:

    i. add a condition that specifies that the Distributor shall, between January 1, 2015 and December 31, 2020, make CDM programs available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of the Distributor's customer base, do so in relation to each customer segment in its service area ("CDM Requirement");

    ii. add a condition that specifies that such CDM programs shall be designed to achieve reductions in electricity consumption;

    iii. add a condition that specifies that the Distributor shall meet its CDM Requirement by:

        a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

        b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

        c) a combination of (a) and (b); and

    iv. add a condition that specifies the Distributor shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other Distributors upon request.

2. Despite paragraph 1, the Board shall not amend the licence of any Distributor that meets the conditions set out below:

    i. with the exception of embedded distributors, the Distributor is not connected to the Independent Electricity System Operator ("IESO") – controlled grid; or

    ii. the Distributor's rates are not regulated by the Board.

3. The Board shall establish CDM Requirement guidelines. In establishing such guidelines, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

i. that the Board shall annually review and publish the verified results of each Distributor's Province-Wide Distributor CDM Programs and Local Distributor CDM Programs and report on the progress of Distributors in meeting their CDM Requirement;

ii. that CDM shall be considered to be inclusive of activities aimed at reducing electricity consumption and reducing the draw from the electricity grid, such as geothermal heating and cooling, solar heating and small scale (i.e., <10MW) behind the meter customer generation. However, CDM should be considered to exclude those activities and programs related to a Distributor's investment in new infrastructure or replacement of existing infrastructure, any measures a Distributor uses to maximize the efficiency of its new or existing infrastructure, activities promoted through a different program or initiative undertaken by the Government of Ontario or the OPA, such as the OPA Feed-in Tariff (FIT) Program and micro-FIT Program and activities related to the price of electricity or general economic activity; and

iii. that lost revenues that result from Province-Wide Distributor CDM Programs or Local Distributor CDM Programs should not act as a disincentive to Distributors in meeting their CDM Requirement.

4. The Board shall establish a DSM policy framework ("DSM Framework") for natural gas distributors whose rates are regulated by the Board ("Gas Distributors"). In establishing the DSM Framework, the Board shall have regard to the following objectives of the government in addition to such other factors as the Board considers appropriate:

   i. that the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

   ii. that the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

   iii. that Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

   iv. that Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

   v. that the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

   vi. that an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

vii. that DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

viii. that lost revenues resulting from DSM programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

5. By January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

6. Nothing in this Directive shall be construed as directing the manner in which the Board determines, under the *Ontario Energy Board Act, 1998*, rates for Gas Distributors or for Distributors, including in relation to applications regarding regional or local electricity demand response initiatives or infrastructure deferral investments.

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Ontario

BY E-MAIL AND WEB POSTING

April 10, 2014

To: All Rate-regulated Natural Gas Distributors
All Licensed Electricity Distributors
All Members of Enbridge Gas Distribution Inc.'s and Union Gas Limited's DSM Consultative Groups

Re: Consultation Process for Developing a New Demand Side Management Framework for Natural Gas Distributors
EB-2014-0134

This letter outlines the consultation process by which the Board will develop a new Demand Side Management (DSM) Framework for rate-regulated natural gas distributors for the period January 2015 to December 2020. It also provides information on the next steps the Board will take to support the conservation and demand management (CDM) activities of licensed electricity distributors for the same period.

Background

The DSM Guidelines for natural gas distributors, issued by the Board on June 30, 2011, provides for a three-year term ending December 31, 2014. As the current DSM term is nearing its conclusion, the Board is initiating a consultation process to review the current DSM Guidelines and develop a new DSM Framework to be used for the development of the next generation of DSM plans.

On March 31, 2014, the Minister of Energy issued a Directive to the Board (the "DSM/CDM Directive") that among other things requires the Board to establish a DSM policy framework and to do so having regard to the following Government objectives:

- That the DSM Framework shall span a period of six years, commencing on January 1, 2015, and shall include a mid-term review to align with the mid-term review of the Conservation First Framework;

- That the DSM Framework shall enable the achievement of all cost-effective DSM and more closely align DSM efforts with CDM efforts, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors;

- That Gas Distributors shall, where appropriate, coordinate and integrate DSM programs with Province-Wide Distributor CDM Programs and Local Distributor CDM Programs to achieve efficiencies and convenient integrated programs for electricity and natural gas customers;

- That Gas Distributors shall, where appropriate, coordinate and integrate low-income DSM Programs with low-income Province-Wide Distributor CDM Programs or Local Distributor CDM Programs;

- That the Board shall annually review and publish the verified or audited results of each Gas Distributor's DSM programs;

- That an achievable potential study for natural gas efficiency in Ontario should be conducted every three-years, with the first study completed by June 1, 2016, to inform natural gas efficiency planning and programs. The achievable potential study should, as far as is appropriate and reasonable having regard to the respective characteristics of the natural gas and electricity sectors, be coordinated with the OPA with regard to the OPA's requirement to conduct an electricity efficiency achievable potential study every three-years;

- That DSM shall be considered to be inclusive of activities aimed at reducing natural gas consumption, including financial incentive programs and education programs; and

- That lost revenues resulting from DSM Programs should not act as a disincentive to Gas Distributors in undertaking DSM activities.

Also, the DSM/CDM Directive states that by January 1, 2015, the Board shall have considered and taken such steps as considered appropriate by the Board towards implementing the government's policy of putting conservation first in Distributor and Gas Distributor infrastructure planning processes at the regional and local levels, where cost-effective and consistent with maintaining appropriate levels of reliability.

DSM Framework for Natural Gas Distributors

Given the evolving policy environment, the Board intends to undertake a comprehensive review of the framework governing gas distributors' DSM activities. In developing the new DSM Framework, the Board will consult broadly with stakeholders.

For the first phase of this consultation, the Board has determined that it would be beneficial to form a DSM Working Group to provide initial input and advice to Board staff on the development of a draft DSM Framework. The draft framework will then be the subject of broader consultation with all interested stakeholders. The composition of the DSM Working Group is described further below.

During the course of the consultation, the Board will specifically consider what elements of the current DSM Framework remain appropriate, and which need to be modified, including: budget levels; program types; targets and incentives; the approval process for DSM plans; and, how to integrate DSM and CDM programs.

To expedite the consultation process, the Board has selected the following organizations to participate on the DSM Working Group:

- Enbridge Gas Distribution Inc.
- Union Gas Limited
- Ontario Power Authority
- Members of the Electricity Distributors Association
- Consumers Council of Canada (CCC)
- Environmental Defence
- Industrial Gas Users Association (IGUA)
- Low Income Energy Network (LIEN)
- Ontario Sustainable Energy Association (OSEA)
- School Energy Coalition (SEC)

The composition of the DSM Working Group was selected to achieve an appropriate representation of consumer, environmental, and utility perspectives. Representatives of the electricity sector have been included on the DSM Working Group given that a number of the Government's objectives, as set out in the DSM/CDM Directive, call for integration or cooperation between the gas and electricity sectors.

The DSM Working Group is expected to meet over the next two months. Materials related to the DSM Working Group, including agendas, meeting schedules, presentations, and meeting minutes will be posted on the Board's website as they become available.

Next steps

<u>DSM Framework for Natural Gas Distributors</u>

As noted above, input from the DSM Working Group will inform the development of a draft DSM Framework. All interested stakeholders will have an opportunity to comment on the draft DSM Framework.

<u>CDM Framework for Electricity Distributors</u>

With respect to electricity CDM, the Board will amend the licences of electricity distributors in the manner set out in the DSM/CDM Directive, and will do so without a hearing as required by the DSM/CDM Directive. The Board will also review what amendments should be made to other regulatory instruments to support the implementation of the CDM Framework.

Cost Awards

Cost awards will be available under section 30 of the *Ontario Energy Board Act, 1998* to eligible persons in relation to their participation in the development of the new DSM Framework. Costs awarded will be recovered from all rate-regulated natural gas distributors based on their respective distribution revenues.

Appendix A contains information regarding cost awards for this consultation, including eligibility requests and objections. In order to facilitate a timely decision on cost eligibility, the deadlines for filing cost eligibility requests and objections will be strictly enforced.

Filing Instructions

All filings made in this consultation process must be made in accordance with the instructions set out in Appendix B.

All material related to this consultation will be posted on the "Policy Initiatives & Consultations" portion of the Board's website at www.ontarioenergyboard.ca. The material will also be available for public inspection at the Board's office during normal business hours.

If you have any questions regarding this DSM Framework consultation process, please contact Josh Wasylyk at Josh.Wasylyk@OntarioEnergyBoard.ca or at 416-440-7723.

The Board's toll free number is 1-888-632-6273.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Appendix A

Cost Awards

Consultation Process for the DSM Framework

Cost Award Eligibility

The Board will determine eligibility for costs in accordance with its *Practice Direction on Cost Awards*. Any person intending to request an award of costs must file with the Board a written submission to that effect by **May 1, 2014** identifying the grounds on which the person believes that it is eligible for an award of costs (addressing the Board's cost eligibility criteria as set out in section 3 of the Board's *Practice Direction on Cost Awards*). An explanation of any other funding to which the person has access must also be provided, as should the name and credentials of any lawyer, analyst or consultant that the person intends to retain, if known. All requests for cost eligibility will be posted on the Board's website.

If a rate-regulated natural gas distributor has any objections to any of the requests for cost eligibility, such objections must be filed with the Board by **May 15, 2014**. All objections will be posted on the Board's website. The Board will then make a final determination on the cost eligibility requests.

The Board has invited a number of stakeholders to participate on the DSM Working Group, including CCC, Environmental Defence, IGUA, LIEN, OSEA and SEC. With the exception of OSEA, all of these DSM Working Group members would generally be considered *prima facie* eligible for an award of costs under the Board's *Practice Direction on Cost Awards.* While OSEA would generally be considered *prima facie* ineligible, the Board's decision to invite OSEA to participate on the Working Group constitutes special circumstances. Therefore, the Board considers it appropriate in the circumstances to waive the following in relation to all of these Working Group participants: (a) the requirement to submit a request for cost award eligibility; and (b) the process for objections which would otherwise have applied in accordance with the Board's *Practice Direction on Cost Awards*.

Eligible Activities

Cost awards will be available in relation to participation on the DSM Working Group, to a maximum equal to actual meeting time multiplied by 1.5 to account for preparation and reporting. Participants will also be eligible to claim costs for other eligible activities that may arise as part of this consultation process.

Cost awards will also be available for additional activities in this consultation process. Details will be provided at the appropriate time.

Cost Awards

When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of its *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied. The Board expects that groups representing the same interests or class of persons will make every effort to communicate and co-ordinate their participation in this process.

The Board will use the process set out in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards. Therefore, the Board will act as a clearing house for all payments of cost awards in this process.

Appendix B

Filing Instructions

Consultation Process for the DSM Framework

Filing Instructions

Three (3) paper copies of each filing must be provided, and should be sent to:

Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto Ontario M4P 1E4

The Board requests that interested parties make every effort to provide electronic copies of their filings in searchable/unrestricted Adobe Acrobat (PDF) format, and to submit their filings through the Board's web portal at https://www.pes.ontarioenergyboard.ca/eservice/. A user ID is required to submit documents through the Board's web portal. If you do not have a user ID, please visit the "e-filings services" webpage on the Board's website at www.ontarioenergyboard.ca, and fill out a user ID password request. Additionally, interested parties are requested to follow the document naming conventions and document submission standards outlined in the document entitled "RESS Document Preparation – A Quick Guide" also found on the e-filing services webpage. If the Board's web portal is not available, electronic copies of filings may be filed by e-mail at boardsec@ontarioenergyboard.ca.
Those that do not have internet access should provide a CD containing their filing in PDF format.

Filings to the Board must be received by the Board Secretary by **4:45 p.m.** on the required date. They must quote file number **EB-2014-0134** and include your name, address, telephone number and, where available, your e-mail address and fax number.

If the filing is from a private citizen (i.e., not a lawyer representing a client, not a consultant representing a client or organization, not an individual in an organization that represents the interests of consumers or other groups, and not an individual from a regulated entity), before making the filing available for viewing at the Board's offices or placing the filing on the Board's website, the Board will remove any personal (i.e., not business) contact information from the filing (i.e., the address, fax number, phone number, and e-mail address of the individual). However, the name of the individual and the content of the filing will be available for viewing at the Board's offices and will be placed on the Board's website.

MAINTENANCE OF EXISTING TRANSPORTATION RATES

In EB-2010-0018, the Board established two transportation rates for NRG, to be levied on any natural gas producer within NRG's service area that utilizes NRG's distribution system to move gas to the Union Gas system (i.e., akin to an electricity transmission "wheeling" charge). The transportation rates approved by the Board were:

- Volumetric: $0.95 per mcf of gas shipped over NRG's distribution system.
- Fixed: $250 per month administration charge for every month NRG's system is used by the producer to transport natural gas to the Union Gas system.

The transportation rates would apply equally to NRG Corp. (a non-arm's length company to NRG) and any arm's length third party producer.

A deferral account was established by NRG to track any revenues that would ultimately accrue to the benefit of NRG's ratepayers. To date, there have been no transportation rate revenues recorded in the deferral account. Since being established by the Board in EB-2010-0018, there have been no producers delivering to Union Gas.

NRG is proposing to leave the existing transportation rates in place for the two-year extension period.