EPCOR RESPONSES TO OEB STAFF INTERROGATORIES

EPCOR Natural Gas Limited Partnership

Application for Rates October 1, 2016 to December 31, 2019, a Fixed Monthly Charge for Rate 6, Disposition of Deferral and Variance Accounts and Approval to Change Rate Year from October 1 to January 1 effective January 1, 2020

EB-2018-0235

Exhibit A – 2016 IRM Application, October 1, 2016 to September 30, 2017

A-Staff-1

Ref: Exhibit A / Page 4

On August 9, 2016 Natural Resource Gas Limited (NRG) filed a rate application (EB-2016-0236) for the period October 1, 2016 to September 30, 2021. The application for the period October 1, 2016 to September 30, 2017 was on a cost-of-service basis and for the remaining years, the proposed rate-setting approach was based on the OEB's 3rd Generation IRM framework for electricity distributors. The application was placed in abeyance at the request of NRG pending the sale of NRG's distribution system assets to EPCOR Natural Gas Limited Partnership (EPCOR). The OEB approved the transfer of the distribution system (MAADs Application, EB-2016-0351) to EPCOR on August 3, 2017 and the transaction closed on November 1, 2017.

a) **Considering that NRG filed its cost-of-service application two months prior to the effective date of October 1, 2016, why does EPCOR presume that an effective date of October 1, 2016 is appropriate?**

b) **The transaction to purchase NRG's distribution system closed on November 1, 2017. In other words, EPCOR starting managing the natural gas utility as of November 1, 2017. Why is EPCOR seeking an adjustment to rates for the period October 1, 2016 to October 30, 2017 considering that it did not own the distribution system assets during that period and did not incur any operating costs to manage the utility?**

c) **Please provide revised bill impacts and rate adjustments for 2017 (November 1, 2017 to September 30, 2018) and 2018 (October 1, 2018 to December 31, 2019) assuming that EPCOR is not permitted to adjust rates for the period October 1, 2016 to October 30, 2017.**

<u>Responses:</u>

a) It is EPCOR Natural Gas Limited Partnership's (EPCOR) understanding that Natural Resource Gas's (NRG) timing related to filing the EB-2016-0236 was driven in a large part by the time required to complete the System Integrity Study which examined the technical and engineering aspects of its system and conclude on the gas required to support system integrity ("Study"). The draft Study was not released by the consultants until January 2016 (per the evidence NRG filed in EB-2016-0236). NRG had been directed to complete and incorporate this Study into their filing.

The Minimum Filing Requirements included in the Natural Gas Distribution Cost of Service Applications dated November 20, 2005 under which NRG filed EB-2016-0236 did not provide guidance on the filing date and effective date of rates. Guidance has been included in the Filing Requirements for Natural Gas Rate Applications dated February 16, 2017. Considering the timing of the Study results and the lack of guidance provided during the time in which NRG filed its application, an effective date of October 1, 2016 seems appropriate.

Subsequent to the filing date of EB-2016-0236, on September 28, 2016 the Board approved NRG's request for the distribution rates effective October 1, 2016 to be declared interim which allowed (but not required) the OEB to retrospectively adjust rates back to this date.

Given these circumstances, EPCOR feels that implementing inflationary adjustments from the effective date of the interim rates is appropriate.

b) Through the purchase transaction EPCOR acquired all of the assets and specific liabilities of NRG which made up the natural gas distribution utility. The timing of the transaction also resulted in EPCOR assuming responsibility for NRG's rate application (EB-2016-0236) and associated commitments. The utility was managed and incurred operating costs prior to the transaction close, for which EPCOR believes the utility should receive compensation regardless of the change in ownership. Furthermore, the utility continued to experience cost increases as a result of regular unavoidable annual inflation. EPCOR's underlying operational cost structure is not significantly different from NRG's and implementing the proposed adjustments covers the annual inflationary increases the utility has experienced over these years and ensures rates set for the future years of the Application account for such inflationary adjustments.

c) The following tables provide revised distribution rates and bill impacts details for 2017 (November 1, 2017 to September 30, 2018) and 2018 (October 1, 2018 to December 31, 2019) should EPCOR not be permitted to adjust rates for the period October 1, 2016 to October 30, 2017.

Table 1 – Current Distribution Rates

Rate Group	Monthly Service Charge	Delivery First 1,000 m^3	Delivery Over 1,000 m^3	Delivery Next 24,000 m^3	Delivery Over 25,000 m^3	Delivery - Firm	Demand - Firm	Commodity	Delivery - Int - Lower	Delivery - Int - Upper
RATE 1 - General Service Rate - Residential	13.50	16.2312	10.9099					0.0363		
RATE 1 - General Service Rate - Commercial	13.50	16.2312	10.9099					0.0363		
RATE 1 - General Service Rate - Industrial	13.50	16.2312	10.9099					0.0363		
RATE 2 - Seasonal Service - Apr to Oct	15.00	15.8212		9.4826	6.1698			0.0363		
RATE 2 - Seasonal Service - Nov to Mar	15.00	19.9424		15.6960	15.2899			0.0363		
RATE 3 - Special Large Volume Contract Rate	150.00					4.0357	29.0974	0.0363	7.9412	10.9612
RATE 4 - General Service Peaking - Apr to Dec	15.00	15.8149	10.5218					0.0363		
RATE 4 - General Service Peaking - Jan to Mar	15.00	20.1755	16.9052					0.0363		
RATE 5 - Interruptible Peaking Contract Rate	150.00					7.1995 [1]		0.0363	5.4612	8.4612
RATE 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility	150.00					3.8894	18.8392		7.9412	10.9612

1 Placeholder rate for average application

Table 2 – Revised Distribution Rates for November 1, 2017 to September 30, 2018

Rate Group	Monthly Service Charge	Delivery First 1,000 m^3	Delivery Over 1,000 m^3	Delivery Next 24,000 m^3	Delivery Over 25,000 m^3	Delivery - Firm	Demand - Firm	Commodity	Delivery - Int - Lower	Delivery - Int - Upper
RATE 1 - General Service Rate - Residential	13.50	16.6067	11.0735					0.0363		
RATE 1 - General Service Rate - Commercial	13.50	16.6067	11.0735					0.0363		
RATE 1 - General Service Rate - Industrial	13.50	16.6067	11.0735					0.0363		
RATE 2 - Seasonal Service - Apr to Oct	15.00	16.4957		9.4826	6.1698			0.0363		
RATE 2 - Seasonal Service - Nov to Mar	15.00	20.7926		15.6960	15.2899			0.0363		
RATE 3 - Special Large Volume Contract Rate	150.00					4.1719	29.0974	0.0363	7.9412	10.9612
RATE 4 - General Service Peaking - Apr to Dec	15.00	16.4049	10.5218					0.0363		
RATE 4 - General Service Peaking - Jan to Mar	15.00	20.9282	16.9052					0.0363		
RATE 5 - Interruptible Peaking Contract Rate	150.00					7.3275 [1]		0.0363	5.4612	8.4612
RATE 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility	150.00					3.9478	19.1218		7.9412	10.9612

1 Placeholder rate for average application

Table 3 – Revised Illustrative Bill Impact Summary for the period November 1, 2017 to September 30, 2018 compared to 11 months of billing* at rates in effect in 2015

Rate Class	Fixed Change	Volumetric Change	Shared Tax Rate Rider	Total Change $	Total Change %
Rate 1 - Residential	**$ -**	**$ 6.01**	**-$ 0.24**	**$ 5.78**	**1.4%**
Rate 1 - Commercial	**$ -**	**$ 21.80**	**-$ 0.24**	**$ 21.56**	**1.7%**
Rate 1 - Industrial	**$ -**	**$ 45.08**	**-$ 0.24**	**$ 44.84**	**1.6%**
Rate 2 - April to October	$ -	$ 41.81	$ 2.70	$ 44.51	1.7%
Rate 2 - November to March	$ -	$ 0.93	$ 2.25	$ 3.18	1.4%
Rate 2 - Annual	**$ -**	**$ 42.74**	**$ 4.96**	**$ 47.69**	**1.7%**
Rate 3 - Special Large Volume Contract Rate	**$ -**	**$ 370.92**	**-$ 53.96**	**$ 316.96**	**1.3%**
Rate 4 - April to December	$ -	$ 33.68	$ 1.30	$ 34.98	2.1%
Rate 4 - January to March	$ -	$ 23.42	$ 0.49	$ 23.91	1.1%
Rate 4 - Annual	**$ -**	**$ 57.11**	**$ 1.78**	**$ 58.89**	**1.5%**
Rate 5 - Interruptible Peaking Contract Rate	**$ -**	**$ 162.52**	**-$ 14.80**	**$ 147.72**	**1.4%**
Rate 6 - Special Large Volume Contract Rate	**$ -**	**$24,733.89**	**-$ 56.02**	**$24,677.87**	**1.5%**

*assumed the average annual consumption level of the rate class is consumed equally throughout the year or season in the case of seasonal rate classes

Table 4 – Revised Distribution Rates for 2018 (October 1, 2018 to December 31, 2019)

Rate Group	Monthly Service Charge	Delivery First 1,000 m^3	Delivery Over 1,000 m^3	Delivery Next 24,000 m^3	Delivery Over 25,000 m^3	Delivery - Firm	Demand - Firm	Commodity	Delivery - Int - Lower	Delivery - Int - Upper
RATE 1 - General Service Rate - Residential	13.50	16.8099	11.1621					0.0363		
RATE 1 - General Service Rate - Commercial	13.50	16.8099	11.1621					0.0363		
RATE 1 - General Service Rate - Industrial	13.50	16.8099	11.1621					0.0363		
RATE 2 - Seasonal Service - Apr to Oct	15.00	16.8608		9.4826	6.1698			0.0363		
RATE 2 - Seasonal Service - Nov to Mar	15.00	21.2528		15.6960	15.2899			0.0363		
RATE 3 - Special Large Volume Contract Rate	150.00					4.2456	29.0974	0.0363	7.9412	10.9612
RATE 4 - General Service Peaking - Apr to Dec	15.00	16.7243	10.5218					0.0363		
RATE 4 - General Service Peaking - Jan to Mar	15.00	21.3357	16.9052					0.0363		
RATE 5 - Interruptible Peaking Contract Rate	150.00					7.3968 [1]		0.0363	5.4612	8.4612
RATE 6 - Integrated Grain Processors Co-Operative Aylmer Ethanol Production Facility	150.00					3.9794	19.2748		7.9412	10.9612

Table 5 – Revised Illustrative Bill Impact Summary for the 15 month period* October 1, 2018 to December 31, 2019 compared to rates in effect in 2015

	October 1, 2018 to September 30, 2019							October 1, 2019 to December 31, 2019				
Rate Class	**Fixed Change**	**Volumetric Change In 2016 IRM**	**Volumetric Change in 2017 IRM**	**Volumetric Change in 2018 IRM**	**2018 Shared Tax Rate Rider**	**PGTVA Disposal**	**REDA disposal**	**Fixed Change**	**Cumulative Volumetric Change**	**2019 Shared Tax Rate Rider**	**Total Change $**	**Total Change %**
Rate 1 - Residential	**$ -**	**$ -**	**$ 6.56**	**$ 3.55**	**-$ 0.26**	**-$ 30.98**	**$ 18.00**	**$ -**	**$ 2.53**	**-$ 0.06**	**-$ 0.66**	**-0.1%**
Rate 1 - Commercial	**$ -**	**$ -**	**$ 23.78**	**$ 12.87**	**-$ 0.26**	**-$ 160.82**	**$ 18.00**	**$ -**	**$ 9.16**	**-$ 0.06**	**-$ 97.33**	**-5.6%**
Rate 1 - Industrial	**$ -**	**$ -**	**$ 49.17**	**$ 26.62**	**-$ 0.26**	**-$ 401.95**	**$ 18.00**	**$ -**	**$ 18.95**	**-$ 0.06**	**-$ 289.53**	**-7.7%**
Rate 2 - April to October	$ -	$ -	$ 48.78	$ 26.40	$ 3.16	-$ 454.90	$ 10.50	$ -	$ 10.74	$ 0.45	-$ 354.87	-10.1%
Rate 2 - November to March	$ -	$ -	$ 0.93	$ 0.50	$ 2.25	-$ 16.24	$ 7.50	$ -	$ 0.57	$ 0.90	-$ 3.59	-1.1%
Rate 2 - 15 months Oct 1/18 through Dec 31/19	**$ -**	**$ -**	**$ 49.70**	**$ 26.91**	**$ 5.41**	**-$ 471.15**	**$ 18.00**	**$ -**	**$ 11.31**	**$ 1.35**	**-$ 358.46**	**-9.3%**
Rate 3 - Special Large Volume Contract Rate	**$ -**	**$ -**	**$ 404.64**	**$ 219.05**	**-$ 58.87**	**-$ 5,873.84**	**$ 18.00**	**$ -**	**$ 155.92**	**-$ 14.72**	**-$ 5,149.81**	**-15.2%**
Rate 4 - April to December	$ -	$ -	$ 37.89	$ 20.51	$ 1.46	-$ 223.37	$ 13.50	$ -	$ 19.47	$ 0.49	-$ 130.06	-5.3%
Rate 4 - January to March	$ -	$ -	$ 23.42	$ 12.68	$ 0.49	-$ 212.11	$ 4.50	$ -	$ -	$ -	-$ 171.02	-7.6%
Rate 4 - 15 months Oct 1/18 through Dec 31/19	**$ -**	**$ -**	**$ 61.32**	**$ 33.19**	**$ 1.95**	**-$ 435.48**	**$ 18.00**	**$ -**	**$ 19.47**	**$ 0.49**	**-$ 301.07**	**-6.4%**
Rate 5 - Interruptible Peaking Contract Rate	**$ -**	**$ -**	**$ 177.30**	**$ 95.98**	**-$ 16.15**	**-$ 2,377.88**	**$ 18.00**	**$ -**	**$ 68.32**	**-$ 4.04**	**-$ 2,038.47**	**-13.7%**
Rate 6 - Special Large Volume Contract Rate	**$ -**	**$ -**	**$26,982.42**	**$ 14,606.49**	**-$ 61.11**	**-$ 544,308.00**	**$ 0.48**	**$ -**	**$ 10,397.23**	**-$ 15.28**	**-$ 492,397.78**	**-21.8%**

*assumed the average annual consumption level of the rate class is consumed equally throughout the year or season in the case of seasonal rate classes

A-Staff-2

Ref: Exhibit A / Page 5-6

EPCOR has filed three IRM applications to adjust rates covering the period October 1, 2016 to December 31, 2019. EPCOR has also requested for the establishment of deferral accounts to record annual amounts for the historic unrecovered IRM adjustments and the annual historic unrecovered shared tax changes.

Please explain why EPCOR has requested deferral accounts to address historic unrecovered amounts as opposed to recovering the foregone revenues directly through a rate rider.

Response:

EPCOR requested deferral accounts to record the unrecovered amounts for later recovery based on the approach typically used to capture items which the utility would then look to recover/return to ratepayers in the future. At the time of filing application EB-2018-0235 it was not yet certain whether the various Exhibits would form one proceeding or be split in some manner therefore EPCOR felt that the best approach was to request the creation of the deferral accounts (in Exhibit A) to allow recording of the amounts since the request for approval to dispose of the amounts through a rate rider was part of a separate Exhibit (Exhibit C).

EPCOR is open to eliminating the step of first recording the amounts in deferral accounts for the historic unrecovered amounts (October 1, 2016 – September 30, 2018). Instead EPCOR would recover the annual historic unrecovered IRM adjustments and the annual historic unrecovered shared tax changes filed for in Exhibit A and Exhibit B directly through a rate rider to be effective October 1, 2018.

A-Staff-3

Ref: Exhibit A / Page 11 / Tables 1 and 2

In tables 1 and 2, EPCOR has provided current rates and proposed rates for the 2017 rate year. In the proposed distribution rates (Table 2), EPCOR has not adjusted the monthly service charge based on the price cap adjustment factor. EPCOR has made further adjustments to the volumetric rate in order to account for the price cap adjustment to the monthly service charge. EPCOR has adopted this method in subsequent IRM adjustments for 2018 and 2019.

a) **Please confirm that under the OEB's 4th Generation IRM framework, both the monthly customer charge and the volumetric charge are to be adjusted based on the price cap adjustment factor.**
b) **Please confirm if there are any other OEB-regulated utilities that have not revised the monthly customer charge to adjust rates under the OEB 4th Generation IRM approach.**
c) **Please explain the reasons for not proposing a modified monthly customer charge for 2017 and subsequent IRM periods to account for the proposed price cap adjustment.**

<u>Responses:</u>

a) EPCOR confirms that per section 3.2.1.1of the OEB's Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 - 4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index dated July 17, 2013, the annual adjustment mechanism should apply to distribution rates (fixed and variable charges) uniformly across customer rate classes.

b) EPCOR is not aware of any other OEB-regulated utilities that have not revised the monthly customer charge to adjust rates under the OEB 4th Generation IRM approach.

c) EPCOR did not propose a modified monthly customer charge for 2017 and subsequent IRM periods to account for the proposed price cap adjustment as the rates proposed were determined by applying the calculations applied by NRG in its previous IRM applications. NRG had received approval for its incentive rate mechanism in its last cost of service application, EB-2010-0018.

The current fixed monthly charges were approved by the Board in EB-2010-0018 for the 2011 test year and have not been modified since that time. In its 2012 IRM application EB-2012-0342, NRG's proposal to change the fixed monthly charges for all customers was not accepted by the Board. In that proceeding, NRG had requested increases to the fixed charges that were above the applicable price cap adjustment factor and the Board's decision and order indicated that NRG's Revised IRM Plan or 3rd generation IRM for EB-2010-0018 did not allow for such changes to the fixed monthly charges[1]. EPCOR understands that NRG interpreted this decision to mean that no increases to the fixed monthly charges were allowed under the IRM plan approved in EB-2010-0018. Accordingly, in the determination of rates for the Draft Rate Order NRG removed all adjustments to fixed monthly charges and instead increased the volumetric charges by an amount required to achieve the price cap adjustment on the revenue for each rate group.[2] The Draft Rate Order was approved by the Board as submitted. NRG applied the same approach of increasing only the volumetric charges in order to achieve the price cap adjustment on the revenue for each rate group in its IRM applications for 2013, 2014 and 2015. The Board approved the proposed rate adjustments calculated in this manner, finding that the rate adjustments proposed by NRG were in accordance with NRG's approved incentive regulation mechanism[3].

EPCOR did not propose a modified monthly customer charge to be consistent with the practice used in prior years for NRG's price cap adjustments. EPCOR's incentive rate setting proposal for its Price Cap IR application for rates effective January 1, 2020 will include adjustments to both fixed and variable charges consistent with the OEB's 4th Generation IRM framework.

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[1] EB-2013-0342 – Decision and Order, February7, 2013, page 6
[2] EB-2012-0342 – Draft Rate Order and NRG Rate Generator Excel file submitted with Draft Rate Order, February 12, 2013
[3] EB-2013-0183 – Decision and Order, August 22, 2013, page 2

A-Staff-4

Exhibit A / Page 12 / Table 3

Table 3 shows the deferred revenue recovery for the period October 1, 2016 to September 30, 2017. In column B, EPCOR has used the current revenue to calculate the price cap adjustment factor of 1.7%.

Please confirm that the current revenue in column B is calculated using 2015 OEB-approved rates and actual volumes for the period October 1, 2016 through September 30, 2017.

<u>Response:</u>

Confirmed that this is the calculation of the table, and amended Exhibit A, Table 3 filed on October 24, 2018 reflects the corrected actual volumes for the period October 1, 2016 through September 30, 2017.

A-Staff-5

Exhibit A / Page 13

In accordance with the IRM plan approved in NRG's last rebasing application (EB-2010-0018), changes in income tax are to be shared 50/50 between the customers and the utility. As part of this application, EPCOR has requested recovery of $17,051 (50% of $34,103) from customers for 2017, 2018 and 2019.

Please confirm that under the OEB's 4th Generation IRM approach, any changes in income tax are to be shared 50/50 between the customers and the utility.

Response:

EPCOR confirms that per section 3.2.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications, Chapter 3 - 4th Generation Incentive Rate-setting and Annual Incentive Rate-setting Index dated July 17, 2013, any changes in income tax are to be shared 50/50 between the customers and the utility.

A-Staff-6

Exhibit A / Page 14 / Table 5

Table 5 provides the illustrative bill impact summary to show the impact of the proposed rate adjustment for the period October 1, 2016 to September 30, 2017.

Please explain why the Shared Tax Rate Rider is a credit considering that EPCOR has proposed to recover $17,051 from customers over the proposed period.

<u>Response:</u>

The bill impact summary in Exhibit A, Table 5 compares the rates proposed for October 1, 2016 to September 30, 2017 to the rates in effect for 2015 (October 1, 2015 to September 30, 2016). In 2015 NRG had a Shared Tax Rate Rider in effect that was higher for a number of rate classes than the Shared Tax Rate Rider proposed by EPCOR for October 1, 2016 to September 30, 2017. The credit in the table reflects the reduction in this rate rider.

A-Staff-7

Exhibit A / Appendix A – Accounting Orders

In the draft accounting orders for the Unrecovered Shared Tax Changes and the Unrecovered IRM Adjustment deferral accounts, the credit entry is to Account No. 632 Gas Purchases.

Please explain why the credit entry is to the Gas Purchase account (an expense account) as opposed to a revenue account.

Response:

Account No.632 Gas Purchases, was provided as the credit account in error. The correct credit account for this should be No. 529 – Gas Sales. This account has been updated in the amended Exhibit A filed on October 24, 2018.

Exhibit C– 2018 IRM Application, October 1, 2018 to September 30, 2019

C-Staff-8

Exhibit C / Page 12

EPCOR has proposed to dispose of the balances in the 2016-2017 Shared Tax Changes Deferral Account and the 2016-2017 IRM Adjustment Deferral Account through the implementation of a rate rider over a twelve month period commencing on October 1, 2018.

a) Has EPCOR received approval to establish the above mentioned deferral accounts?
b) Considering that EPCOR has not received OEB approval to establish the Shared Tax Changes and the IRM Adjustment deferral accounts, how does it intend to dispose of the balances in this proceeding?

<u>Responses:</u>

a) EPCOR has not yet received approval to establish the Unrecovered Shared Tax Changes Deferral Account and the Unrecovered IRM Adjustment Deferral Account. EPCOR has requested approval to establish these accounts as part of the 2016 IRM Application in Exhibit A.[4] EPCOR had not requested the creation of deferral accounts for the recording of such unrecovered historic amounts prior to this application since EPCOR's approach to EB-2016-0236 and finalizing rates for the period October 1, 2016 to December 31, 2019 had only recently been finalized.

b) Given the approach of dealing with all applications within the exhibits of EB-2018-0235 as one proceeding, EPCOR is open to recovering the annual historic unrecovered IRM adjustments and the annual historic unrecovered shared tax changes filed for in Exhibit A and Exhibit B directly through rate riders to be effective October 1, 2018, thereby eliminating the administrative steps associated with setting up, recording and disposing of the amounts through deferral accounts. The 2016-2017 Shared Tax Rate Rider would be as calculated in Exhibit C, Table 4 and the 2016-2017 IRM Adjustment Rate Rider would be as calculated in Exhibit C, Table 5.

[4] EB-2018-0235 – Application and Evidence, Exhibit A – 2016 IRM Application, July 27, 2018, page 6

C-Staff-9

Exhibit C / Pages 5-6

In EPCOR's application for the 2019 rate year, October 1, 2018 to September 30, 2019, it has requested disposition of the balances in the 2016-2017 Shared Tax Changes Deferral Account and the 2016-2017 IRM Adjustment Deferral Account through the implementation of rate riders. However, there are no proposed additions to the deferral accounts in order to capture 2017-2018 adjustments.

a) Will EPCOR be seeking recoveries for the foregone revenue related to 2017-2018 Shared Tax Changes and IRM adjustments? If yes, when?
b) If the foregone revenue for 2017-2018 was recovered what amounts would be recorded in the Shared Tax Changes and the IRM Adjustment Deferral Accounts?

<u>Responses:</u>

a) It was EPCOR's intent to request recovery of the foregone revenue related to 2017-2018 Shared Tax Changes and IRM adjustments as part of its cost of service filing for rates commencing January 1, 2020. However, further to EPCOR's response to C-Staff- 8 above, EPCOR proposes an alternative approach of recovering the 2017-2018 unrecovered IRM adjustment and the 2017-2018 unrecovered shared tax changes directly through rate riders (to be effective October 1, 2018), thereby eliminating the administrative steps associated with setting up, recording and disposing of the amounts through deferral accounts.

b) If the foregone revenue for 2017-2018 was recovered through deferral accounts, $219,833 would be recorded in the IRM Adjustment Deferral Account which would be the difference between the revenue collected at the 2015 rates and compared to the proposed rates and $17,051 in the Shared Tax Changes Deferral Account as at September 30, 2018.

Exhibit D– Application for a Fixed Monthly Charge for Rate 6

D-Staff-10

Exhibit D / Page 6

EPCOR has proposed a fixed monthly charge to recover costs for serving Integrated Grain Processors Co-operative (IGPC) under Rate 6. The modified rate structure would eliminate the recovery associated with increases in IGPC's volumes and would set the revenue for the 2019 rate year from IGPC equal to the revenue proposed in the 2018 IRM application. The revenue would be recovered through twelve flat monthly fixed payments.

a) **Does EPCOR's proposal to recover IGPC related costs through a fixed monthly charge recover all costs incurred to serve IGPC including the allocation of administrative and regulatory costs? Please provide a detailed response.**
b) **Is the proposal to move to a fixed monthly charge for Rate 6 a permanent rate design change?**

<u>Responses:</u>

a) The proposed fixed rate was calculated by applying the rates proposed for Rate 6 in Exhibit C to IGPC's actual volumes and contracted demand for October 1, 2016 to September 30, 2017. Since the rates proposed in Exhibit C are based on the costs as allocated to IGPC in EB-2010-0018, the proposed fixed monthly charge recovers all costs to provide service to IGPC as identified in EB-2010-0018, NRG's most recent cost of service filing. The cost allocation study approved by the Board in EB-2010-0018 included allocations for administrative and regulatory expenses, as well as other costs to provide service to IGPC.

b) Yes, the proposed fixed monthly charge for Rate 6 is a permanent rate design change.

D-Staff-11

Exhibit D / Page 6

On page 7 of Exhibit D, EPCOR has provided rationale supporting the monthly fixed charge for Rate 6. The applicant notes that the monthly fixed charge will provide IGPC with stable and predictable distribution costs and the proposal is supported by IGPC.

Can EPCOR provide any written communication with IGPC that validates support for the proposed approach?

<u>Response:</u>

The proposed approach was agreed to between IGPC and NRG prior to NRG filing EB-2016-0236 and was documented in a Delivery Agreement between the two parties dated June 30, 2015, which has been included as Attachment 1. Furthermore, in recent meetings between IGPC and EPCOR, IGPC has verbally confirmed that they are still in agreement with the proposed approach.

Exhibit E – Application for Disposition of PGTVA, REDA and IFRS Conversion Cost Deferral Accounts

E-Staff-12

Exhibit E / Pages 5-6

The credit balance in the PGTVA for customers in rate classes 1 to 5 as of September 30, 2017 is $428,919 and for Rate 6 (IGPC), the credit balance is $544,304 for a similar period. The balances include interest and are proposed to be disposed of over a twelve month period, from October 1, 2018 to September 30, 2019. In the EB-2017-0215 application, NRG requested a correction to the reference prices used in the PGTVA to record the variance between forecast and actual transportation costs. NRG submitted that there was a calculation error in NRG's last rates proceeding (EB-2010-0018) as the reference price was based on Union Gas Limited's transportation volumes rather than NRG's load forecast sales volume. The OEB allowed NRG to make the correction and the corrected credit balances as of September 30, 2015 was $428,722 plus $18,887 in interest for rate classes 1 to 5 and $527,067 plus $31,853 in interest for rate class 6 (IGPC).

The credit balances as of September 30, 2015 and September 30, 2017 are not very different. Please provide reasons for the minimal change in the balances from September 30, 2015 to September 30, 2017.

Response:

The PGTVA records the difference between the forecast and actual transportation costs for Union Gas Limited to deliver natural gas to EPCOR (and formerly NRG). The minimal change in the PGTVA balances from September 30, 2015 to September 30, 2017 is because the difference between the reference price for PGTVA 1-5 and PGTVA 6 as set out in EB-2017-0215 and the calculated average cost over this two-year period is just over 3% as shown in the table below.

PGTVA 1-5	**Reference Price EB-2017-0215**	**Average for the period Sept 2015 to Sept 2017**
Volume M^3	**21,932,940**	24,845,349
% difference		13%
Transportation Cost $	**402,220**	470,451
% difference		17%
Average Cost $/M³	**0.018339**	**0.018935**
% difference		**3.25%**
PGTVA 6	**Reference Price EB-2017-0215**	**Sept 2015 to Sept 2017 Annual Average**
Volume M^3	**33,416,816**	38,579,590
% difference		15%
Transportation Cost $	**330,310**	394,108
% difference		19%
Average Cost $/M³	**0.009885**	**0.010215**
% difference		**3.35%**

Note 1: Annual volumes and transportation costs as per EB-2018-0236 Exhibit E PGTVA Continuity Schedule

E-Staff-13

Exhibit E / Pages 6-7

The balance in the Regulatory Expense Deferral Account (REDA) and the IFRS Conversion Cost Deferral Account (IFRSDA) as of September 30, 2017 is $158,260. EPCOR has proposed to dispose of the balance relating to both the REDA and the IFRSDA over a twelve month period from October 1, 2018 to September 30, 2019. The IFRSDA account balance has been allocated to rate classes 1 through 6 based on the number of customers in each rate class. The REDA balance includes activities related to customers using the low pressure distribution system (Rates 1 to 5) and not served with the dedicated high-pressure pipeline (Rate 6). EPCOR has provided continuity schedules associated with the accounts in Excel format.

a) Please provide the type of costs that are included in the IFRSDA?
b) The costs incurred in the REDA deferral account are not allocated to Rate 6. Please explain why costs related to corporate governance, cyber security and regulatory costs should not be allocated to Rate 6.

<u>Responses:</u>

a) The costs included legal fees associated with participating in IFRS consultations with Board staff and coordinating with NRG staff on the matter, as well as an invoice from the OEB for the IFRS consultation cost awards and hearing costs.

b) EPCOR agrees that the corporate governance, cyber security and applicable regulatory costs could be allocated to Rate 6. The costs related to these items are included in the "Other REDA" balance along with other immaterial items. Given that the Other REDA balance is made up of a number of small items, EPCOR chose not to break this out further and to allocate entirely to rate classes 1 through 5 since the majority of the overall REDA activities do not relate to Rate 6. As the sum of the corporate governance, cybersecurity and associated regulatory costs is $3,802 they do not have a material impact on the REDA rate riders calculated in Exhibit E. The allocation of these costs to all customers would result in an increase to the monthly rate rider for Rate 6 of $0.04 ($3,802 divided by 8,775 customers divided by 12 months), and a decrease for customers in rate classes 1 to 5 of the same amount.

E-Staff-14

Continuity Schedule – PGTVA and REDA (Excel)

In the Excel spreadsheet that shows the continuity schedule of the REDA account, there are costs under the heading, "Application for Service – put to capital cost of pipeline".

a) **Please confirm that these costs are related to providing service to IGPC and have not been allocated to or proposed to be recovered from other rate classes.**
b) **Does the balance of $158,260 as of September 30, 2017 in the REDA account include costs that are under the heading, "Application for Service – put to capital cost of pipeline"? If yes, please explain why these costs are included.**

<u>Responses:</u>

a) These costs are not related to providing service to IGPC, rather they are related to EB-2015-0308, the Application for Gas Distribution Service from Union Gas Limited ("Union Gas") that NRG filed in 2015 requesting gas distribution services from Union Gas to address system pressure issues in NRG's Northeastern franchise area. The legal and consultant costs associated with this application were initially tracked in the REDA account and were later moved to property, plant and equipment and capitalized with the assets put in place by NRG as part of the solution agreed to by the parties as a result of this application for service and the associated discussions with Union Gas.

b) The September 30, 2017 balance in the REDA account of $158,275 does not include any of the costs related to the Application for Service. The balances related to these costs were capitalized and removed from REDA prior to 2017.

E-Staff-15

Continuity Schedule – PGTVA and REDA (Excel)

In the Excel spreadsheet that shows the continuity schedule of the REDA account, there are costs related to Demand Side Management (DSM).

Considering that EPCOR does not implement DSM initiatives, please explain the costs related to DSM in the spreadsheet.

<u>Response:</u>

In 2014 and 2015 NRG participated in the DSM Framework working group initiative of the Board and NRG was encouraged to look at developing a cost-effective DSM program.

At the time NRG also operated a water heater rental business and looked to leverage this for its DSM program. NRG installed a tank-less water heater to measure abatement and efficiency of the tank-less water heaters versus the tanked styles that the company had in its rental portfolio, and later installed a tank-less unit in a combined heating system to measure the saving over a traditional furnace. The costs in the REDA account relate to the installation of these two tank-less water heaters to measure efficiency.

The installations showed minimal efficiency and NRG did not further pursue the development of a DSM program given that it could not offer a cost-effective DSM program given the cost versus abatement of the water heater option. NRG later sold the water heater rental business.

ATTACHMENT 1 to D-Staff- 11

Delivery Agreement between the IGPC and NRG dated June 30, 2015

GAS DELIVERY AGREEMENT

This natural gas delivery agreement (the "**Agreement**") made this 30th day of June 2015 (the "**Effective Date**")

BETWEEN:

NATURAL RESOURCE GAS LIMITED, (the "**Utility**"),

and

IGPC ETHANOL INC. (the "**Customer**"),

(each a "**Party**" and collectively the "**Parties**")

WHEREAS the Customer requires the delivery of natural gas to its ethanol facility located in the Town of Aylmer and Utility has the franchise for the distribution of natural gas in the Town of Aylmer;

NOW THEREFORE, in consideration of the mutual covenants and agreements contained in this Agreement, and for other good and valuable consideration (the receipt and adequacy of which are hereby acknowledged), the Parties agree as follows:

TYPE OF SERVICE:

___ Firm Demand

___ Interruptible Demand

___ Combined Firm and Interruptible Demand

RATE CLASS: 6

DAY OF FIRST DELIVERY: July 1, 2015

PART 1 - DEFINITIONS

(a) For the purpose of interpreting this Agreement, the capitalized terms shall have the following meaning, unless the context requires otherwise:

(i) "**Agreement**" means this Gas Delivery Agreement including schedules as such may be amended from time to time;

(ii) "**Applicable Rate**" means the distribution rate, including rate riders and rate adders, approved by the OEB that the Utility is authorized to charge the Customer;

(iii) "**Business Day**" means any day that is not a Saturday, Sunday or statutory holiday in the Province of Ontario;

(iv) "**Customer Delivery Point**" means the Customer's facility located at the address known municipally as 89 Progress Drive, Aylmer, Ontario;

(v) "**Force Majeure**" has the meaning ascribed to it in Schedule B;

(vi) "**Joint Rate Proposal**" has the meaning ascribed to it in Part 5 of this Agreement;

(vii) "**Maximum Daily Volume**" means the maximum daily volume of natural gas required to be delivered by Utility to Customer pursuant to Part 4 of this Agreement;

(viii) "**Maximum Hourly Volume**" means the maximum hourly volume of natural gas required to be delivered by Utility to Customer pursuant to Part 4 of this Agreement;

(ix) "**Minimum Volume**" means the minimum volume of natural gas that the Customer is required to accept and pay for over any particular period of time during the Term, as set out in Part 4 of this Agreement;

(x) "**Governmental Authority**" means any federal, provincial, regional, municipal or local government or authority or other political subdivision thereof, and any Person, court, tribunal, agency, board, commission or department, exercising executive, legislative, judicial, regulatory, or administrative functions of, or pertaining to, government or having jurisdiction in the relevant circumstances, including, without limitation, the Ontario Energy Board;

(xi) "**Ontario Energy Board**" or "**OEB**" means the Ontario Energy Board or any successor organization that has authority to set rates for the provision of natural gas delivery service in Ontario.

PART 2 - TERM & TERMINATION

This Agreement shall be effective as of the Effective Date first written above and, unless terminated earlier in accordance with the provisions hereof, shall expire on September 30, 2020 (the "**Term**").

PART 3 - PURCHASE AND SALE

During the Term, except during periods of curtailment, discontinuance or Force Majeure:

(a) the Utility agrees to deliver natural gas from the Union Gas Limited distribution system to the Customer Delivery Point, up to the Maximum Daily Volume and Maximum Hourly Volume set out in Part 4; and

(b) Customer agrees that it will receive from the Utility all of the natural gas delivered to the Utility by the Customer, up to the Maximum Daily Volume and Maximum Hourly Volume set out in Part 4.

The natural gas received by the Utility and delivered to the Customer 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. Neither Party is responsible for any loss, damage, or injury resulting from such Party's delivery of gas that does not conform to any specifications set forth in this section, except to the extent any loss, damage or injury arises as a result of such Party's negligence or wilful misconduct.

PART 4 - MAXIMUM DAILY VOLUME AND MINIMUM VOLUME

First Period Contract Parameters:

For the period from July 1, 2015 to earlier of the commencement of the Second Period or Third Period (the "**First Period**"):

(a) Maximum Daily Volume: The Maximum Daily 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.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall not exceed 5,410 m^3.

(c) Minimum Volume: The Minimum Volume of natural gas that the Customer is required to accept and pay for in each month of the First Period shall be 2,784,718 m^3.

(d) Utility Curtailment Right: Should the Customer consume more than 5,410 m^3 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 5,410 m^3/hour. Consumption in excess of 5,410 m^3/hour by the Customer shall not be considered to be a breach of this Agreement.

(e) New Maximum Daily Volume: Should the Customer exceed the Maximum Daily Volume on any day before the new rate structure is effective, then this higher number will be the new Maximum Daily Volume under this Agreement until a new rate structure is effective, and the Maximum Hourly Volume specified herein shall be adjusted accordingly, subject to being able to make any arrangements with Union Gas Limited that may be required.

Second Period Contract Parameters:

The Utility shall make commercially reasonable efforts to amend its M9 contract with Union Gas Limited (for dedicated supply to the Customer) to increase the Maximum Daily Volume to

130,000 m^3 and the Maximum Hourly Volume to 6,100 m^3 by October 1, 2015. If NRG is able to amend its upstream M9 contract with Union Gas Limited (the "**Amended M9 Contract**"), then the First Period parameters shall no longer be applicable, and the following parameters shall apply until such time as the OEB establishes new rates for NRG based on a re-basing rate application (the "**Second Period**"):

(a) Maximum Daily Volume: The Maximum Daily 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 the Firm Contract Demand in the Amended M9 Contract.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall not the Maximum Hourly Flow in the Amended M9 Contract.

(c) Minimum Monthly Volume: The Minimum Volume of natural gas that the Customer is required to accept and pay for in each month of the Second Period shall be 2,784,718 m^3.

(d) Utility Curtailment Right: Should the Customer consume more than the Maximum Hourly Flow in the Amended M9 Contract 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 equivalent to the Maximum Hourly Flow in the Amended M9 Contract. Consumption in excess of the Maximum Hourly Flow in the Amended M9 Contract by the Customer shall not be considered to be a breach of this Agreement.

(e) New Maximum Daily Volume: Should the Customer exceed the Maximum Daily Volume on any day before the new rate structure is effective, then this higher number will be the new Maximum Daily Volume under this Agreement until a new rate structure is effective, and the Maximum Hourly Volume specified herein shall be adjusted accordingly, subject to being able to make any arrangements with Union Gas Limited that may be required.

The Customer agrees that it shall be responsible for any costs billed by Union Gas Limited to NRG associated with the Amended M9 Contract, including without limitation, any capital costs to accommodate the increased volumes. Such costs will not be marked up by NRG.

Third Period Contract Parameters:

For the period commencing with the establishment of new rates for NRG based on a re-basing rate application, and ending on the earlier of the Termination of this Agreement or September 30, 2020 ("**Third Period**"):

(a) Maximum Daily Volume: The Maximum Daily 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 only be limited by the capacity limits of the Utility's distribution system and the upstream Union Gas Limited distribution system.

(b) Maximum Hourly Volume: The Maximum Hourly Volume of firm gas the Utility is required to deliver to the Customer in any hour shall only be limited by the capacity limits of the Utility's distribution system and the upstream Union Gas Limited distribution system. Revisions to the Maximum Hourly Volume and therefore the Fixed Contract Demand will be subject to approval of Union Gas Limited and Customer.

(c) Minimum Volume: If the OEB approves the Joint Rate Proposal set out in Part 5 below, the Customer shall have no Minimum Volume obligation under this Agreement. If the OEB does not approve the Joint Rate Proposal set out in Part 5 below, the Customer and Utility will negotiate in good faith to establish an annual Minimum Volume obligation that enables the Utility to recover that portion of its revenue requirement allocated to the Customer.

(d) Utility Curtailment Right: Should the Customer consume at any time an amount that is adversely impacting the Utility's ability to safely and reliably operate its distribution system, the Utility may curtail service to a volume equivalent to the Maximum Hourly Flow in the Amended M9 Contract. Consumption in excess of the Maximum Hourly Flow in the Amended M9 Contract by the Customer shall not be considered to be a breach of this Agreement.

PART 5 - 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 Agreement 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) applicable to or for such service, in accordance with the provisions of the Utility's Rate 6 schedule in effect at any time during the term of this Agreement.

Utility shall use commercially reasonable efforts to have a new rate application finally determined by the OEB by September 30, 2016.

For the period prior to the new rate structure being effective, if the Utility, pursuant to Part 8 of this Agreement, or due to an event of Force Majeure as described in the General Terms and Conditions, fails or is unable to deliver the amount of firm natural gas which the Customer desires to take during any one or more days in a month, up to the Customer's Maximum Daily Volume 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 Maximum Daily Volume exceeds the volume of gas delivered to the Customer Delivery Point on such a day, for each day in the month in which the inability to deliver continues.

The Utility shall, at its next cost of service rebasing application for distribution rates, currently forecasted to commence October 1, 2016, propose a new Rate 6 schedule wherein the Customer would pay a flat monthly fixed charge that would enable the Utility to recover the forecasted annual revenue requirement allocated to Customer (the "**Joint Rate Proposal**") in 12 monthly payments. The Joint Rate Proposal shall be composed of the following two components:

(a) a fixed monthly charge to permit recovery of the cost of distribution service as determined by the OEB, excluding the M9 charges of Union Gas Limited; and

(b) the pass-through, without mark-up, of all charges billed to the Utility by Union Gas Limited related to all gas supplied to the Utility's distribution system for Customer. For greater certainty, this shall include all Union Gas Limited charges to the Utility under the M9 Contract or Amended M9 Contract between the Utility and Union Gas Limited (Union Contract ID SA008936, as amended or replaced from time to time), and the Bundled-T Contract between the Utility and Union Gas Limited (Union Contract ID SA008937, as amended or replaced from time to time).

Rater riders and rate adders shall be applicable as determined by the OEB.

In addition, the new Rate 6 should permit Utility to recover each month any penalties in respect of the Customer's deliveries or consumption of natural gas properly imposed by a third party (including without limitation, Union Gas Limited) on a cost pass-through basis, with no separate unauthorized overrun charge levied by NRG.

Provided the Utility has received approval as to the form of the Joint Rate Proposal from the Customer, the Customer agrees to support the form of the Joint Rate Proposal at NRG's next application for distribution rates before the OEB. The Customer may intervene in the rate application and take any position it deems appropriate regarding the Utility's revenue requirement, cost allocation and quantum of the proposed Rate 6 or other aspect of the Utility's rate application other than the form of the Joint Rate Proposal.

For the period following the effective date of new rate structure, if the Utility, pursuant to Part 8 of this Agreement, or due to an event of Force Majeure as described in the General Terms and Conditions, fails or is unable to deliver the amount of firm natural gas which the Customer desires to take during any one or more days in a month, then the monthly bill for that month shall be reduced on a proportional basis to the amount that the Customer would have taken in the month in the absence of any curtailment or discontinuance.

PART 6 - POINT OF DELIVERY

The Customer Delivery Point of all natural gas delivered by the Utility is at the outlet of the Utility's metering equipment at the Customer's 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 7 - PRIORITY OF SERVICE

In the event of an 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 Governmental Authority, the Customer shall at the direction of the Utility, curtail or discontinue use of natural 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 maybe ordered by such Governmental Authority among all industrial Rate 3 and Rate 6 customers of the Utility. 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 8 - CURTAILMENT OR DISCONTINUANCE OF SERVICE

Firm service under this Agreement will be provided up to the Maximum Daily Volume.

Notice of curtailment or discontinuance of service may be conveyed by telephone, in person, by mail, facsimile or email to Customer. 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 the notice and provide the reasons for the curtailment or discontinuance of service 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 9 - GENERAL TERMS AND CONDITIONS

The General Terms and Conditions attached as Schedule B form part of this Agreement.

PART 10 - SECURITY DEPOSIT

During the Term of this Agreement, the Customer shall provide and maintain a security deposit in respect of the distribution service with the Utility in an amount equal to the maximum amount of distribution services for a period of two months, as calculated below, using the Applicable Rate at the Day of First Delivery. 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 Day of First Delivery using the Applicable Rate on such date.

During the First Period and Second Period, the maximum amount of the security deposit will be equal to:

Security Deposit = Monthly Customer Charge + Demand Charge + Delivery Charge

Where:

Monthly Customer Charge = the fixed monthly charge specified in Rate 6 x 2

Demand Charge = Firm Agreement Demand x Firm Demand Rate x 2

Delivery Charge = Firm Delivery Rate x Firm Agreement Demand x 60

During the Third Period, the maximum amount of the security deposit will be equal to:

Security Deposit = (Monthly charge to permit recovery of the cost of NRG's distribution service PLUS Monthly charge to permit recovery by Utility of the M9 charges from Union Gas Limited) x 2

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.

For greater certainty, if the Utility is entitled to draw upon the security deposit and draws down upon the security deposit in whole or in part, the Customer shall replenish the amount of the security deposit in the same form and to the maximum amount noted above within 15 Business Days.

If Customer shall be indebted (whether past, present, or future, liquidated or unliquidated) to Utility under this Agreement, Utility has the right to reduce any amount payable by Utility to Customer under this Agreement by an amount equal to the amount of such indebtedness to Utility. As part of this remedy, Utility may take title to any or all of Customer's gas in Utility's system. Such gas shall be valued at the day price for gas at Dawn as listed in Canadian Gas Price Reporter for the day of non-payment.

PART 11 - INVOICING & PAYMENT

All invoices from Utility to Buyer will be delivered to Customer's address as noted below. Monthly invoices will be prepared 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 OEB shall be referred to the OEB 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 five (5) Business Days.

Monies found to be owing to the Utility at the resolution of the dispute shall be paid by the Customer within five (5) 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 OEB approved late payment charge for any late payment, including any payment that is unsuccessfully disputed by the Customer. Costs will be determined under the *Electricity and Gas Inspection Act* or by the arbitrator or the OEB as applicable.

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 8 above, or of an event of Force Majeure, any notice or other communication required to be given by either Party to this Agreement 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 Limited
39 Beech St. E.
P.O. Box 307
Aylmer, Ontario N5H 281
Telephone: 519-773-5321
Facsimile: 519-773-5335

Or in the case of notice to the Customer, except notice of Force Majeure or curtailment, to it at:

IGPC Ethanol Inc.
89 Progress Drive
Aylmer, Ontario

Attention: Mr. Jim Grey, President and CEO
Telephone: (519) 765-2575 ext. 228
Facsimile: (519) 765-2775

Or in the case of Force Majeure or curtailment, to the Customer at:

IGPC Ethanol Inc.

Attention: Plant Manager
Telephone: (519) 765-2575 ext. 231

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 Agreement, 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 Agreement.

NATURAL RESOURCES GAS LIMITED

By: ______________________________
Name: ANTHONY N. GRAAT
Title: PRESIDENT

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

IGPC ETHANOL INC.

By: ______________________________
Name: Jim Grey
Title: President and CEO

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

Or in the case of Force Majeure or curtailment, to the Customer at:

IGPC Ethanol Inc.

Attention: Plant Manager
Telephone: (519) 765-2575 ext. 231

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 Agreement, 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 Agreement.

NATURAL RESOURCES GAS LIMITED

By: ______________________________
Name:
Title:

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

IGPC ETHANOL INC.

By: ______________________________
Name: Jim Grey
Title: President and CEO

By: ______________________________
Name:
Title:
I/We have authority to bind the corporation.

SCHEDULE A
OEB APPROVED RATE SCHEDULE

NATURAL RESOURCE GAS LIMITED

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

Rate Availability

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

Eligibility

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

Rate

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

a) Monthly Customer Charge of $150.00 for firm services

Rate Rider for reduction in Aid to Construct - effective until September 30, 2016	$(41,786.54)
Rate Rider for Shared Tax Savings - effective until September 30, 2015	$(602.26)

b) A Monthly Demand Charge:

A Monthly Demand Charge of 18.6158 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 3.8432 cents per m^3,

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

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

e) Overrun Gas Charges:

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

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

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

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

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

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

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

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

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

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

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

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

Bundled Direct Purchase Delivery

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

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

Delayed Payment Penalty

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

Effective: July 01, 2015
Implementation: All bills rendered on or after July 01, 2015
EB-2015-0191

NATURAL RESOURCE GAS LIMITED

SCHEDULE A – Gas Supply Charges

Rate Availability

Entire service area of the company.

Eligibility

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

Rate

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

PGCVA Reference Price	(EB-2015-0191)	20.1173 cents per m^3
GPRA Recovery Rate	(EB-2015-0191)	0.6337 cents per m^3
System Gas Fee	(EB-2010-0018)	0.0363 cents per m^3
Total Gas Supply Charge		20.7873 cents per m^3

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

Effective: July 01, 2015
Implementation: All bills rendered on or after July 01, 2015
EB-2015-0191

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. If the Utility becomes aware of any proposed change to this Agreement being considered by the Ontario Energy Board, the Utility shall provide the Customer with notice of such proposed change.

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 6 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. The Utility acknowledges that the existing measurement facilities are suitable for measurement of the Maximum Daily Volumes and Maximum Hourly Volumes set out in Part 4 of this Agreement.

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 by Customer, 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. The Utility, following such inspection, shall forthwith take any and all corrective action necessary to ensure compliance with the *Electricity and Gas Inspection Act*, R.S.C. 1985, c. E-4, as amended from time to time.

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*, R.S.C. 1985, c. E-4, as amended from time to time.

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.

4.2 Utility may be required from time to time to perform maintenance or carry out construction on its facilities, which may impact Utility's ability to meet Customer's requirements. In such event, Utility will have the right to suspend any service in whole or in part but will use reasonable efforts to determine a mutually acceptable period during which such maintenance or construction will occur and also to reasonably limit the extent and duration of any impairments. Utility shall provide at least fifteen (15) days' notice (except in cases of emergency, in which event it may be done immediately with notice provided as soon as reasonably possible afterwards) to Customer of the extent that Utility's ability to provide service may be impaired. During any such curtailment, Customer will be relieved of all demand charges for services directly related to the said curtailment, but commodity and proportionate demand charges for services available to Customer will be payable.

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 Agreement, 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;

(c) curtailment of firm transportation or firm storage by other natural gas service providers;

(d) strikes, lockouts or other industrial disturbances, riots, sabotage, insurrections, civil disturbance, acts of terrorism, wars, arrests or restraint of governments and people;

(e) any laws, orders, rules, regulations, acts of any government body or authority, civil or military;

(f) any act or omission by parties not controlled by the Party claiming Force Majeure; and

(g) 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 commercially 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 claim of Force Majeure was caused by the negligence or wilful misconduct of the Party claiming suspension or a person for whom such Party is responsible for at law;

(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, which shall include funds no longer available under any government grant, assistance or program; 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.

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 Agreement will continue to be payable. The Minimum Volume shall be reduced in the same proportion as the number of days of Force Majeure in the time period covered by the Minimum Volume requirement.

5.8 The term of this Agreement 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 Agreement shall be interpreted, performed and enforced in accordance with the laws of the Province of Ontario and the laws of the Canada applicable therein.

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 Agreement 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 This Agreement may be executed by the parties in counterparts and may be executed and delivered by facsimile or other electronic means and all such counterparts, facsimiles or other electronic means shall together constitute one and the same agreement.